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A TECHNICAL AND ECONOMIC EVALUATION OF USING A NUCLEAR ENERGY SOURCE TO PRODUCE LIQUID HYDROGEN FOR USE AS AN AIRCRAFT FUEL

by

KENNETH RICHARD KARR

A thesis submitted in partial fulfillment
of the requirements for the degree of

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Approved by ______________________________
(Chairman of the Supervisory Committee)

Department ______________________________
(Departmental Faculty Sponsoring Candidate)

Date ______________________________

Master's Thesis

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TABLE OF CONTENTS

List of Figures

List of Tables

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Abstract

Technical and economic implications of introducing liquid hydrogen as a fuel for aircraft are surveyed. The hydrogen would be produced from water using a nuclear energy source. By-products such as electricity, heat, and oxygen would be used in the airport terminal area and the local community. Criteria for the energy production and conversion systems are established, and alternative systems are discussed. For the nuclear energy source, a high-temperature, gas-cooled reactor with a gas turbine conversion system (HTGR-GT) is selected as best meeting the desired criteria.

Estimates of liquid hydrogen and by-product demand are made for the year 1990 and are used in a benefit-cost analysis to determine the desirability of siting the facility at the Seattle-Tacoma Airport. Nuclear reactors would be sited underground. A benefit-cost ratio (BCR) of 0.81 is found, indicating that quantified project benefits do not exceed quantified project costs. Many economic benefits and costs are not easily quantified, however, and are discussed qualitatively. Non-quantified benefits appear to outweigh non-quantified costs and tend to increase the overall economic value of the proposed project.

The economic analysis is very sensitive to escalation rates of fossil fuel prices. If jet fuel prices escalate at a rate of 9.4% compared with an average escalation of 8%, the project would be economically competitive. The price of jet fuel has increased at a much higher rate in the recent past, but future behavior is uncertain.

The cost of liquid hydrogen is estimated at \$3.26 per 10^6 BTU (\$0.168 per pound) in 1974 dollars. The impact of several contingencies affecting the price of jet fuel, heating fuel, and oxygen are explored.

Variations in the parameters of this evaluation are proposed for future study.

I. INTRODUCTION

The need to develop alternative portable fuel resources becomes evident daily. Frequently, mention is made of the potential that hydrogen may hold as a replacement for fossil fuels, particularly derivatives of petroleum products. Hydrogen may be produced from water by electrolysis thereby eliminating fossil raw materials that are required in most other feasible methods of formation. The electrical energy can be supplied by nuclear fuels.

The application of hydrogen as a fuel to the economy introduces many technological and safety factors that are difficult to foresee, at least initially, in the relatively unsupervised areas of consumption like home heating and automobile propulsion. An introduction of hydrogen as a fuel into the more highly developed and controlled technologies such as aircraft propulsion seems more plausible. Entry into other areas of the economy could follow and employ many spin-offs from features designed for distribution and control of hydrogen systems used in the future commercial air carrier industry.

A potential for additional economical and environmental gains may exist if, in addition to being used as an aircraft fuel, the by-products, heat, electricity, and oxygen, are exploited at or near the source of production.

The purpose of this study is to develop a preliminary evaluation of a synergistic concept incorporating the gains possible by designing and locating a nuclear energy source underground at an airport. Technical and economic factors will be considered. The airport studied in this evaluation

is the Seattle-Tacoma airport, but the conclusions can be extended to other major airports in the United States with mostly minor alterations.

The evaluation consists of an estimate of fuel requirements for aircraft, the selection of appropriate nuclear and thermal-electric conversion systems, selection and design estimates of a hydrogen production, liquifaction and storage system, synergistic applications postulations and design estimates, an economic evaluation and a subjective evaluation.

II. SYSTEM SELECTIONS

Energy Source

In choosing the specific design of a power source numerous factors must be considered. The following general considerations are employed:

State of technology

The target date for on-line production of hydrogen for aircraft was arbitrarily chosen as 1990. Therefore, the technology must be available today or must be developed sufficiently that reasonable extensions of today's technology could easily encompass the intended concepts. In this respect, pressurized water, boiling water, and high temperature gas reactors are considered since all have been proven on a commercial basis.

Location

A number of factors must be considered in selecting the location for the power plant. This study is based on an airport location. Split plant concepts (nuclear plant in one location, hydrogen production plant in another) and concepts employing a unified plant at distant locations have been left to subsequent evaluations. Because of the airport location, additional operating and safety restrictions will be encountered due to the proximity of population centers and the hazards associated with aircraft operations. Other considerations include the availability of methods of rejecting waste heat, the availabity of consumable resources (eg. water and fuel), and seismic stability. Finally, the installation must be visibly attractive.

Cost

The cost of the plant must be as low as practicable.

Thermal features

In order to provide the most advantageous thermal efficiency for the production of electricity, hydrogen, and useable by-products (oxygen and thermal energy), a power source exhibiting the highest feasible exhaust temperatures is desirable. The former is desired since the efficiency of the system is proportional to the difference between output and exhaust temperatures divided by the output temperature (Carnot), and the latter is desirable in order to provide for small exhaust equipment (particularly when dry cooling is required) and more efficient transportation of waste heat.

Size

Land space at or near an airport is limited and valuable. Furthermore, underground siting costs depend upon the size of the containment required for the type of power plant under consideration. For these reasons, the volume of the system for a given power rating should be as small as possible.

Potential for future improvements

Some power plant designs, notably the high temperature gas reactor (HTGR) types, have several features that offer potential for future development or improvement, particularly in the areas of improved fuel utilization and in higher output temperatures (and therefore improved efficiency). These are considered in the power system selection.

Reliability

The power plant selected must have prospects of being highly reliable. An on-line factor of 85% is utilized in this analysis, therefore,

any plant selected must offer good prospects for equaling or exceeding this figure. By 1990, it is hoped that pressurized water and boiling water reactors will have improved their performance in this respect. In the case of HTGR's, foreign operating experience will be relied upon in order to predict reliability in addition to the Peach Bottom HTGR prototype, since full-scale commercial operation has not been achieved in the United States.

Wastes

Disposal of spent fuel wastes is presently a perplexing problem. A consideration will be made in favor of the reactor that minimizes the quantity of these wastes and toward the reactor that produces the least difficult to handle wastes. Furthermore, a zero atmospheric release system will be required.

Selection

Upon weighing the foregoing considerations, the high-temperature gas reactor coupled to a gas turbine thermal cycle (HTGR-GT) seems to most effectively combine the characteristics stated as desired. Figure 1 is a schematic diagram of this system, and Figure 2 a temperature entropy diagram for this system. This system is not yet in operation, however, in General Atomic's survey of the high temperature gas reactor and turbine fields the technology has been developed and tested for the individual components[1] Most significantly, General Atomic has an active program leading to the full-scale commercial production of this reactor type by 1986. The HTGR portion of this plant is operational on the prototype scale with the 40 MWe Peach Bottom plant. The 300 MWe HTGR at the Fort

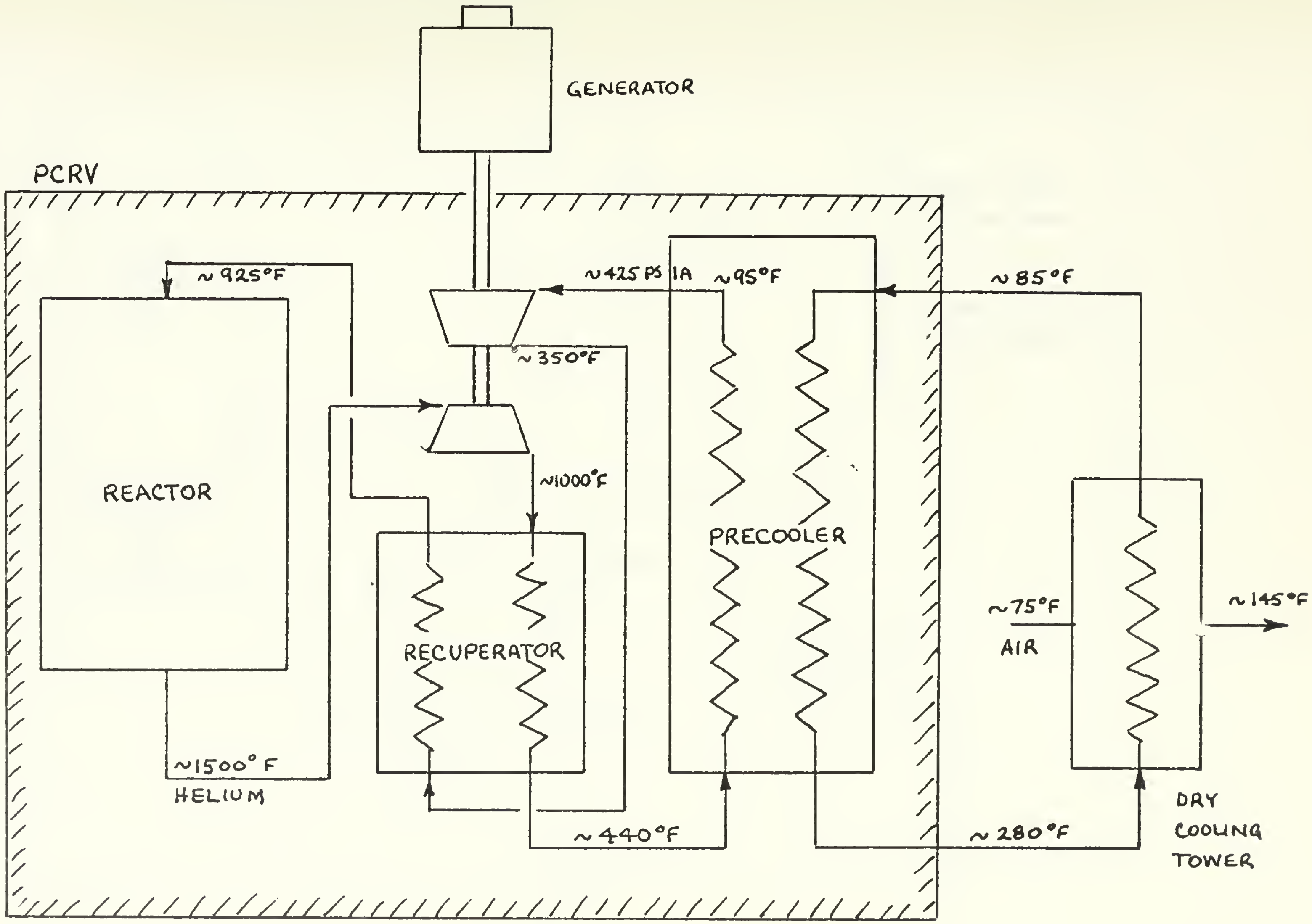

Figure 1
HTGR-GT Simplified Schematic Diagram

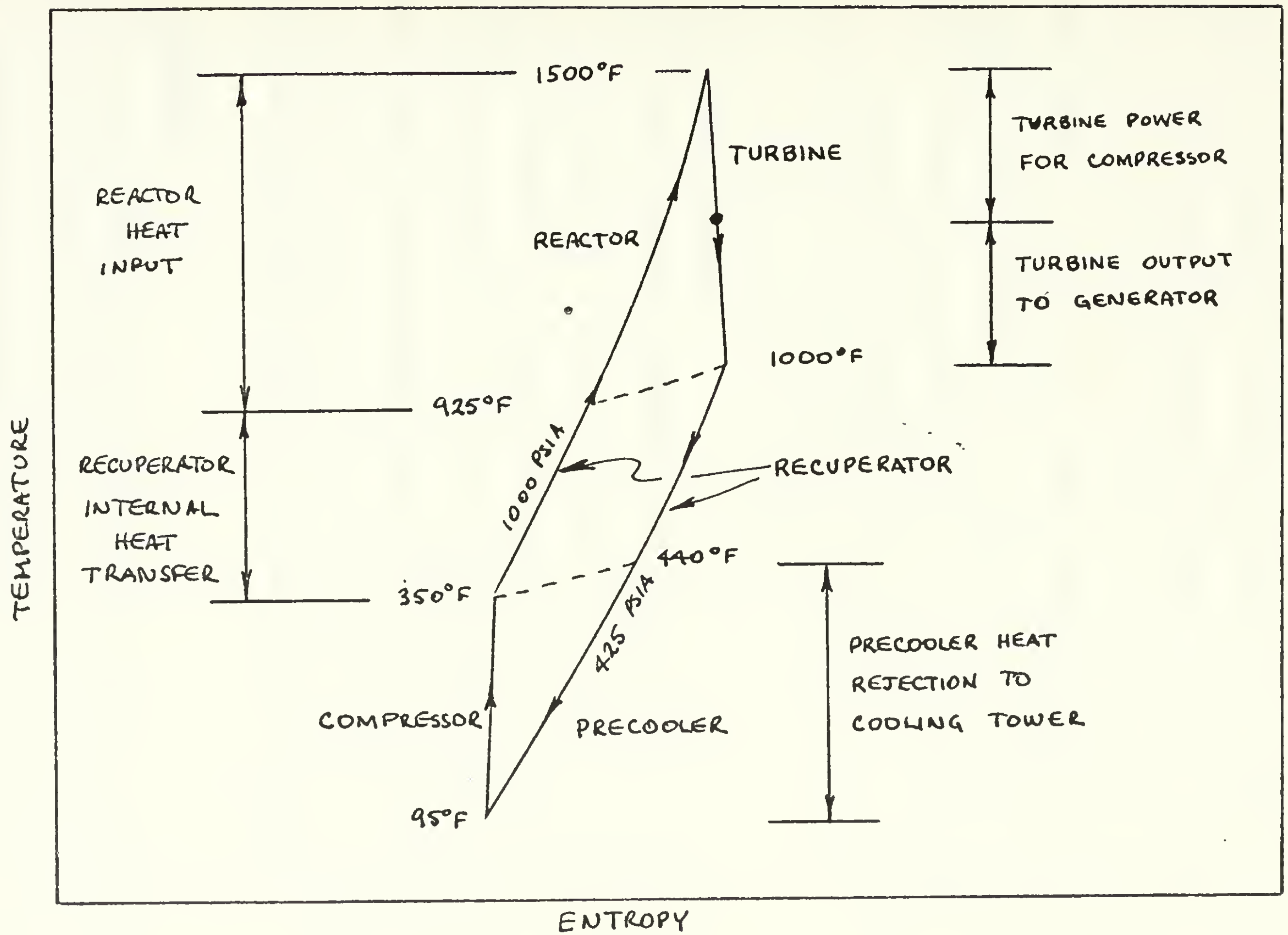

Figure 2

HTGR-GT Simplified Thermodynamic Cycle

St. Vrain facility is the first to include a prestressed concrete reactor vessel (PCRV), and is presently coming on-line. Commercial interest in the HTGR nuclear steam supply system has been strong, indicating a relatively high degree of confidence in a commercially untested design. Utility financial support has been received in General Atomic's five year research and development program, which includes a significant amount of money for the construction of a gas turbine HTGR loop demonstration test facility[2]. It is apparent that, although not in operation, the HTGR-GT does meet the selection criteria of this evaluation; that it lies within today's technology. A comparison of the HTGR-GT characteristics with those outlined for consideration of the power source is as follows:

State of technology

This topic has been developed to a large extent in the foregoing remarks introducing the decision to employ an HTGR-GT. The HTGR-GT is technically feasible, is planned for commercial scale operation by 1990, and has received widespread commercial interest and support. Within this category, however, the pressurized water and boiling water reactors must be acknowledged as superior due to the fact that they are in commercial operation on a large scale today and thus technically proven.

Location

All of the reactor types considered can meet the requirements outlined for locating at an airport with the exception that the low exhaust temperatures for either pressurized or boiling water reactor types require large surface areas for transferring heat to the environment or to secondary heat utilization equipment. Because the HTGR-GT exhausts at

high temperatures, dry cooling towers can be made much smaller than the comparable requirements for wet cooling towers used with the PWR or BWR types of reactors, providing the advantage to the HTGR-GT in this category in presenting a lesser hazard to aircraft, requiring less space, and providing more potential for being made visibly attractive.

Cost

Costing a plant not in production is not possible, and best-guess information must be used from sources most interested in portraying a small cost, i.e., the developer of the HTGR-GT itself. Through information provided by local utilities, it has been found that General Atomic claims a 12% savings in cost when employing the HTGR-GT with dry cooling over the cost of the HTGR steam cycle plant with dry cooling[3]. They further claim that the cost of a dry-tower-cooled HTGR gas turbine plant is approximately the same as that of a wet-tower-cooled HTGR steam cycle plant[4]. Further estimates obtained from local utilities indicate that the HTGR steam cycle plant is competitive to within 5% of the costs of comparably sized PWR and BWR nuclear steam supply systems[5]. Overall, this makes the HTGR-GT the least expensive plant for this type of installation or any other, for that matter.

Thermal features

As mentioned previously, smaller cooling towers using dry air cooling are possible with the HTGR. Also, the HTGR is thermally more efficient than PWR or BWR reactors because it operates at higher temperatures and at a correspondingly greater efficiency. Whereas PWR and BWR reactors operate near 30% efficiency, the HTGR-GT is predicted to operate

at 37%[6]. An additional feature of high exhaust temperatures is that the transport and transfer of rejected heat to potential process heat and space heat users is economical. The HTGR-GT, therefore, provides significant advantages over other types of reactors when considering the expanded range of applications for space and process heat that it can provide.

Size

The size of the containment building of the HTGR-GT is less than that required for the PWR and BWR designs by about 25%[7]. Since the containment portion is to be sited underground, this represents a significant saving in the cost of excavation and other reinforcements that are characteristic of underground siting. The gas turbine equipment is included in the containment with the HTGR-GT[8], providing a significant reduction in above-ground space requirements. This, coupled with the reduced size of dry cooling towers, makes the HTGR-GT a far more attractive candidate than the PWR or BWR reactors when considering the overall size of the installation. The size of accessory buildings and equipment associated with the electrolysis and liquifaction plants does not depend on the type of nuclear energy source.

Potential for future improvements

Unlike the PWR and BWR reactors, whose designs are limited by the present state of the art in high temperature metallurgy in core design, the HTGR core, consisting of graphite fuel elements containing coated particles of uranium dicarbide as fissle material and thorium carbide as the fertile material, is not subject to these limitations. Present commercial HTGR design outlet temperatures for the primary gas coolant are

near 1400°F with outlet steam temperatures between 950 and 1000°F[9]. An increase in outlet temperature to a level of 1650°F (about 1250° if correlating to steam cycle steam supply temperature) is possible by several practical means within today's technology, and an increase to between 1850 and 1950°F with significant engineering development in fuel, PCRV thermal barrier, and heat exchanger materials[10]. The use of inert helium reduces the complexity of HTGR's compared with water-cooled plants, which are subject to severe corrosion in both the primary and secondary heat exchanger.

The HTGR is a converter with a conversion ratio of about 0.85[11]. Thorium is the fertile material that is employed and is more plentiful than uranium[12]. However, no reactor in the foreseeable future could use only the ^{232}Th-^{233}U cycle because of the breeding required to produce a net surplus of ^{233}U. Over a period of many years, the best that could be expected would be a sharing of the nuclear fuel market and a gradual increase in the availability of ^{233}U. General Atomic has designed a gas cooled fast breeder reactor (GCFR) that has a predicted breeding ratio of about 1.47 for fertile thorium[13]. Although this reactor type cannot support the high outlet temperature possible with the HTGR, it could be used in conjunction with the three 1500 MWe HTGR-GT installations that are required in this study. As the capacity requirements grow over the thirty-year expected life of the project, a self-sustaining complex using the bred fuel to supply the HTGR's would be possible. This is shown schematically in Figure 3[14]. Of all the concepts investigated, only the HTGR seems to offer significant promise for dramatic future developments.

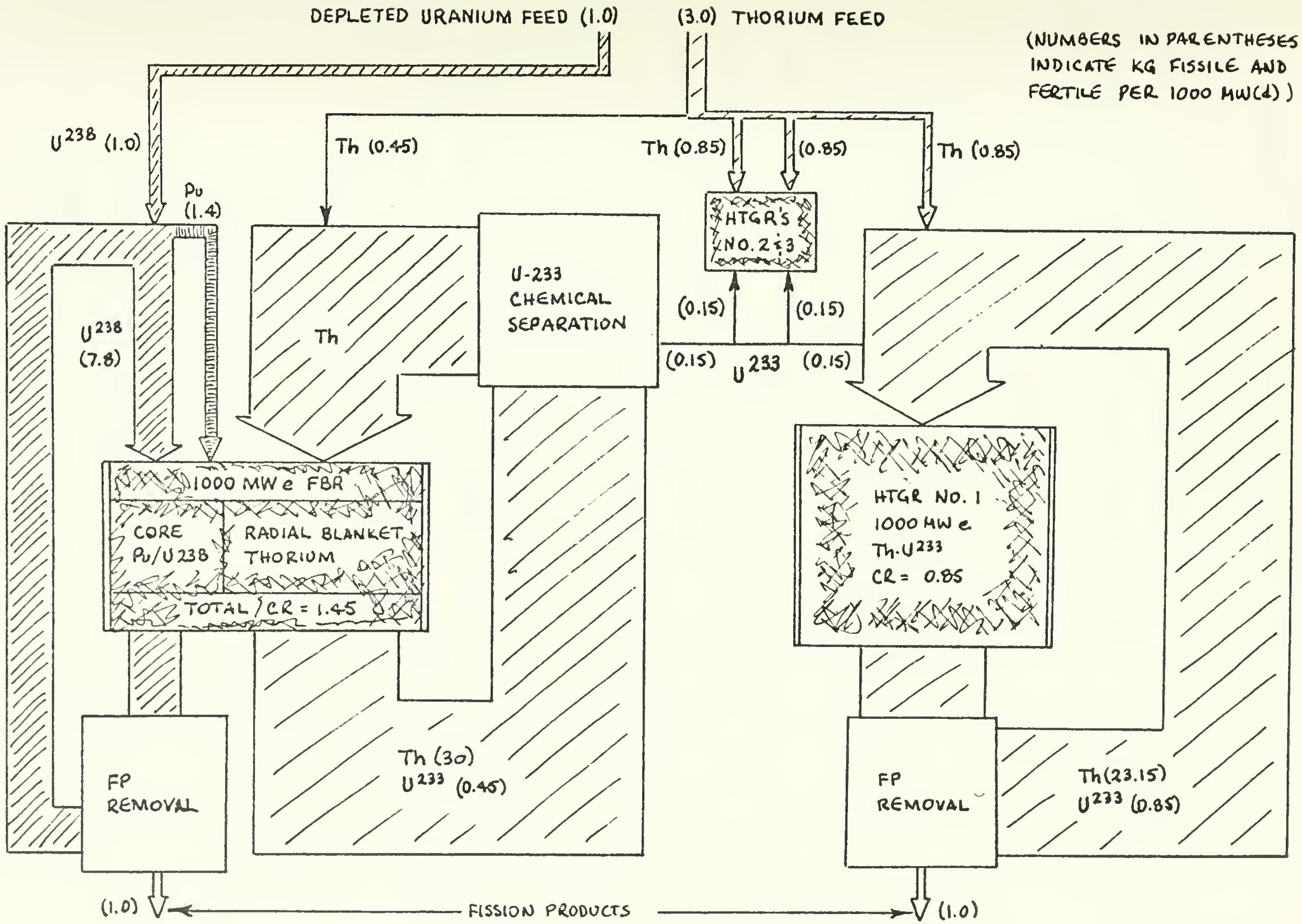

Figure 3
Fuel Mass Flow Diagram for Self-Sustaining FBR-HTGR Combination System

Reliability

Recent figures (December 1974) indicate that the PWR and BWR reactors presently in commercial operation have exhibited availability factors far below the 80% desired. During the first nine months of 1974, the average availability factor was 68.1% for the 40 licensed nuclear power plants in the United States[15]. In terms of its potential reliability, General Atomic cites the fact that actual world experience with gas-cooled reactors is more favorable than with any other type of reactor. Data as of January 1, 1970, indicated that gas-cooled reactors represented 48% of the world's nuclear generating capacity and accounted for 67% of the total cummulative energy generated by nuclear plants[16]. The Peach Bottom HTGR plant has operated without a single instance of steam generator tube failure or forced outage of the helium circulators[17]. Since high temperature helium is to operate a high-speed gas turbine, the potential for failure here as well must be addressed. General Atomic has indicated to local utilities that design of the helium driven gas turbine falls in a temperature range below those for virtually all the major gas turbine applications, military and industrial, being exploited today[18]. Roughly illustrating this are the estimated inlet temperature progressions cited below:

R & D Engines......................2900°F

Military Aircraft..................2600°F

Commercial Transports..............2400°F

Industrial Applications............1900°F

HTGR-GT............................1500°F

Obviously, a considerable potential for reliable operation exists with the HTGR-GT, but it is evident that the size of equipment and capacity of the cores represent unknown factors that could negate the promising features mentioned. The 68% availability of PWR and BWR plants is not good enough to provide an advantage in this category and the potential of the HTGR-GT to exceed this seems excellent.

Wastes

Although all nuclear reactors release far less gaseous radioactivity to the environment than permitted by Federal Regulations, General Atomic points out that the release from an HTGR is exceptionally low because the helium coolant is practically free of induced radioactivity and is also continuously purified during plant operation, ultimately resulting in releases less than 1/10,000 those permitted[19]. To reduce on-site releases by PWR's and BWR's below current levels the addition of major purification systems would be required with an attendant increase in cost. Long-term waste disposal is not significantly different between the water reactors and the HTGR-GT. The advantage in this category thus lies with the HTGR-GT.

Summary

A survey has been conducted to qualitatively assess the characteristics appropriate to PWR, BWR, and HTGR reactor types. The HTGR appears to provide significant advantages for the project under consideration in seven of the eight specific categories addressed. The only strong constraint on choosing the HTGR-GT concept is that the state of technology is not well developed in the integrated whole. The individual components of the HTGR-GT system: Peach Bottom HTGR prototype, gas turbine technology,

prestressed concrete pressure vessel etc., are well within the present state of the art. Occasionally the combination of several technologies introduces unforseen synergistic complications that could provide a significant degree of risk when considering this alternative. The seven very significant advantages that have been pointed out outweigh these risks, particularly in light of the very well developed areas of technology that are employed in the overall concept and in the high potential for further technical improvements to permit higher HTGR outlet temperatures and for improving fuel utilization when combined with a gas cooled fast breeder reactor.

For these reasons, the HTGR-GT is selected as the nuclear energy source for the liquid hydrogen, electricity and heat energy complex to be sited underground at Seattle-Tacoma airport.

Potential for Alternate Hydrogen Production

By selecting a hydrogen production system tied to a thermal-mechanical-electric conversion cycle, inefficiencies are encountered that can be circumvented by a direct heat-chemical conversion process. Although not technically feasible today, several promising developments have been presented recently in the literature concerning the potential for thermochemical water-splitting to produce hydrogen. An example of such a process is as follows[20]:

$$2CrCl_2 + 2HCl \rightarrow 2CrCl_3 + H_2$$

$$2CrCl_2 \rightarrow 2CrCl_2 + Cl_2$$

$$\underline{H_2O + Cl_2 \rightarrow 2HCl + \tfrac{1}{2}O_2}$$

$$H_2O \rightarrow H_2 + \tfrac{1}{2}O_2$$

This process is one of literally thousands of potential candidates for the specific chemical compounds to be employed. The largest effort to produce such a process was begun in 1969 at the Euratom Laboratory at Ispra, Italy. Since then, others have become active in investigating these types of processes, including German research at Julich (KFA) and the University of Aachen, and the United States research projects at the Institute of Gas Technology, Argonne National Laboratory, Los Alamos National Laboratory, General Electric Company and the General Atmoic Company[21]. All processes are tied directly to thermodynamic efficiencies limited by the Carnot efficiency. However, the different compounds used in the analyses under study do provide different overall thermodynamic efficiencies. Further, the different compounds also display different degrees of corrosiveness, an extremely important factor when combined with a high-temperature heat source such as a high-temperature gas reactor. This leads to an optimization problem that some researchers are attempting to solve using computers[22]. The principle advantage over electrolysis is the potential for increasing the energy utilization efficiency from about 31%, which seems to be the maximum attainable using electrolysis, to about 61% with optimum conditions (which include high-temperature reactions). This particular field of study seems to offer much promise for dramatic break-throughs between the present and 1990. With high-temperature thermo-chemical reactions developed on a commercial scale the costs of large processes could be far reduced from those such as electrolysis, since the former can be carried out in larger and larger "batch" processes, whereas additional electrolysis modules must be continuously added at reduced economies to scale.

III. LIQUID HYDROGEN FUEL REQUIREMENTS FOR AIRCRAFT

In estimating the liquid hydrogen fuel requirements for aircraft in 1990, four factors are taken into account: the quantity of fossil jet fuel consumed presently, the fraction of present consumption that could be utilized by liquid hydrogen fueled aircraft, the increase in aircraft potentially adaptable to liquid hydrogen fuel from the present to 1990, and the weight of fossil jet fuel required to provide an identical payload-distance performance for a given weight of liquid hydrogen jet fuel. Combining these factors to yield an average liquid hydrogen fuel demand can be expressed as follows:

$$LH_2 = (J)(g_{wb})(f_{90})/(f_{jh})$$

where:

LH_2 = annual average liquid hydrogen demand in 1990 (tons/day)

J = annual average fossil jet fuel consumption by all commercial aircraft in 1973 (tons/day)

g_{wb} = fraction of all aircraft fuel in 1973 that could be replaced with liquid hydrogen fuel

f_{90} = ratio of potential liquid hydrogen aircraft fuel usage in 1990 to that in 1973

f_{jh} = ratio of the weight of fossil jet fuel to liquid hydrogen fuel required to achieve an identical payload-distance performance

These factors are determined by the procedure provided in Appendix B, and are summarized as follows:

Present Consumption of Fossil Jet Fuel

All fuel is delivered to the Seattle-Tacoma Airport through the Facilities of Olympic Pipeline Company. Correspondence with this company provided an estimate for the year ending in June, 1973, of a daily average consumption of 2087 tons. Therefore, J = 2087 tons per day.

Fraction of All Aircraft Fuel Consumed in 1973 that Could be Replaced with Liquid Hydrogen Fuel

Although it is possible to provide liquid hydrogen as a fuel for all commercial aircraft, it is not clear whether the advantages outweigh the disadvantages for smaller planes[23]. For this reason, only wide body aircraft are assumed to use liquid hydrogen fuel in 1990. Therefore, the fraction of wide body aircraft fuel use in 1973 is utilized to extrapolate to 1990 fuel requirements. The value of g_{wb} determined in Appendix B is 0.182.

Ratio of the Weight of Fossil Jet Fuel to Liquid Hydrogen Fuel Required To Achieve an Identical Payload-Distance Performance

The heat of combustion of fossil jet fuel presently in use by aircraft is 18,600 BTU/lb and that for liquid hydrogen jet fuel is 51,500 BTU/lb at standard conditions (see Appendix A). If considering only the weight ratio required to yield an identical energy release in combustion, a ratio of 2.77 lbs fossil jet fuel to liquid hydrogen jet fuel is attained.

Because the aircraft is required to carry less weight, in fuel, the amount of energy required for a given payload is decreased. The Boeing Company has reported an increase in the fuel weight ratio required to achieve an identical payload-distance performance from 2.77 to 2.96 for a

Boeing 747 converted to liquid hydrogen fuel. Furthermore, weight ratios as high as 4.61 have been reported[24]. This was an estimate by NASA for a subsonic cargo transport designed expressly for liquid hydrogen fuel. Personal communication with the Boeing Company has led to the conclusion that fossil to liquid hydrogen fuel ratios in excess of 3.00 are prematurely optimistic[25]. For this reason $f_{jh} = 2.96$ is selected.

Ratio of Potential Liquid Hydrogen Aircraft Fuel Usage in 1990 to that in 1973

A recent study conducted by the Port of Seattle provides comprehensive data concerning predicted trends in air traffic volumes through 1993 in terms of aircraft types and number of estimated departures[26]. These estimates, summarized as Table 13, combined with figures for aircraft fuel consumption reported in Aviation Week and Space Technology[27], number of available wide body aircraft passenger seats, and fuel consumption per passenger seat-mile, yield an estimate of wide body aircraft liquid hydrogen consumption in 1990 and are displayed in Table 14. The detailed calculations shown in Appendix B yield $f_{90} = 10.21$.

Annual Average Liquid Hydrogen Demand in 1990

From the relation developed at the beginning of this section, it is seen that the average consumption of liquid hydrogen by aircraft in 1990, LH_2, is 1310 tons per day.

Seasonal Variations in Jet Fuel Consumption

The electrolysis plant designed to produce the hydrogen required for aircraft must be able to provide a sufficient quantity for the peak months of liquid hydrogen utilization. For this reason, calculations, based on

data obtained from a recent Port of Seattle aviation demand forecast for the years 1970 through 1972 monthly aircraft departures, have been made in Appendix C providing fractions on a monthly basis of the average annual demand. These fractions are presented in Table 16. It is noted that a maximum of 1.152 is indicated for the months of July and August, 1971. This figure is used in the following section of this study in sizing the electrolysis and liquifaction plants.

IV. HYDROGEN PRODUCTION, LIQUIFACTION AND STORAGE

The preceeding portions of this study have been concerned with developing the concept and selecting the optimum components for a plant to produce liquid hydrogen for aircraft propulsion and to estimate the quantity of liquid hydrogen that is likely to be needed by 1990 to fuel applicable aircraft.

This section will address the specific design parameters for the plant under consideration in order to determine the capacity of the nuclear power plant, the electrolysis plant, the liquifaction plant, and the liquid hydrogen storage facilities.

The System

Figure 4 provides a simplified schematic diagram showing the five major components of the liquid hydrogen production and distribution system. These include the energy source (HTGR-GT) that produces electrical power for electrolysis ($MW_{e\ell}$) and for liquifaction ($MW_{\ell q}$), the electrolysis that produces gaseous hydrogen (H_2), the liquifaction plant that takes the electrolysis output (H_2) and liquifies it ($LH_{2\ell}$), the storage system that takes the liquifaction output ($LH_{2\ell}$), stores it, then provides its output to the distribution system (LH_{2d}), then finally, the aircraft that fuels from the distribution system ultimately retaining a quantity of fuel (LH_2) for propulsion. Losses are encountered throughout the system and must be taken into account in the design. The overall power capacity of the HTGR-GT required for liquid hydrogen (MW_{LH2}) is a function of the efficiencies and losses throughout the system.

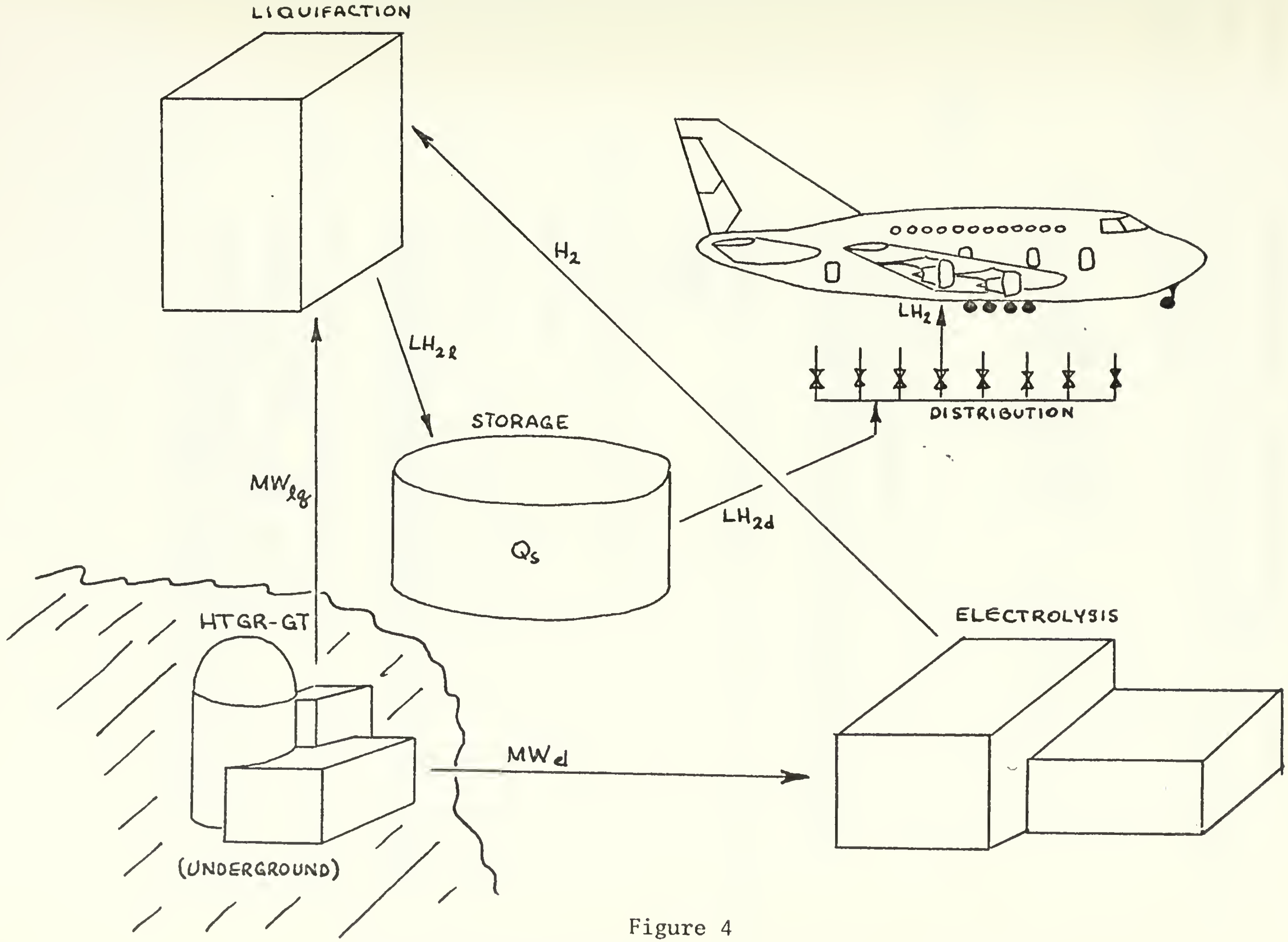

Figure 4

Liquid Hydrogen Production, Liquifaction, Storage and Distribution - Simplified Schematic

A detailed derivation of a relationship between the electrical power required for electrolysis and liquifaction (MW_{LH_2}) and the various efficiencies and losses encountered in the overall system is found in Appendix D. This relation is as follows:

$$MW_{LH_2} = [\frac{1.257}{\eta_e} + \frac{q}{12}][\frac{LH_2}{\eta_d} + f_{h\ell} Q_s]/\eta_{op}\eta_\ell$$

where:

η_e = Electrolysis efficiency

$[(\frac{\text{BTU combustion, } H_2}{\text{lb } H_2})/(\frac{\text{BTU electrolysis energy}}{\text{lb } H_2})]$

q = Electrical energy required to liquify 1 lb of hydrogen

$[\frac{\text{kw-hr}}{\text{lb } H_2}]$

LH_2 = Liquid hydrogen fuel demand

[tons/day]

η_d = Efficiency of the liquid hydrogen distribution system

$[\frac{\text{tons liquid hydrogen reaching aircraft fuel tanks}}{\text{tons liquid hydrogen entering distribution system}}]$

$f_{h\ell}$ = Fraction of stored liquid hydrogen lost daily due to storage tank heat leak boiloff

$[\frac{\text{tons liquid hydrogen boiled off from heat leak daily}}{\text{tons liquid hydrogen stored in tanks}}]$

Q_s = Quantity of liquid hydrogen stored in tanks [tons]

η_{op} = Fraction of liquid hydrogen left after boiloff from heat generated in ortho- to para-hydrogen conversion

$$\frac{\left[\text{tons/day liquid hydrogen delivered by liquifaction system} - \text{tons/day boiled off due to ortho- to para-hydrogen conversion heat generation}\right]}{\text{tons/day delivered by liquifaction}}$$

η_{ℓ} = Efficiency of the liquifaction plant in converting gaseous hydrogen to liquid hydrogen

$$\left[\frac{\text{tons liquid hydrogen leaving liquifaction unit}}{\text{tons gaseous hydrogen entering liquifaction unit}}\right]$$

and the units of the two constants are as follows:

$$1.257 \ \left[\frac{\text{mw-day}}{\text{ton } H_2}\right]$$

$$1/12 \ \left[\frac{\text{lb-mw-day}}{\text{ton kw-hr}}\right]$$

The annual daily average requirement for liquid hydrogen to fuel aircraft was estimated in a previous section of this analysis, and found to be:

$$LH_2 = 1310 \text{ tons/day}$$

The other factors in the above relationship for electrical energy required for electrolysis and liquifaction must be estimated and are the subject of the following sections.

Electrolysis efficiency (η_e)

A wide range of electrolysis efficiencies are reported in the literature. Some authors suggest that efficiencies on the order of 100% are achievable in the near future[28], while others being marketed today provide an efficiency near 56%[29]. The in-depth study of hydrogen production on a large scale by Hallett in 1967 utilized an electrolysis efficiency of approximately 70%[30]. Also in 1967, Costa and Grimes presented an Alis-Chalmers electrolysis design capable of yielding an efficiency of near 83%[31]. In view of the opportunity for further improvements in electrolysis system designs between now and the year that these units would have to be ordered for installation in time to go on line in 1990, the value presented by Costa and Grimes has been selected for use in this analysis. Therefore, η_e is 0.83.

Electrical energy required for liquifaction (q)

Few data are available on the design and cost of hydrogen liquifaction plants. Of 18 sessions held recently on the hydrogen economy at the School of Engineering and Environmental Design, University of Miami, almost no mention of this important cost factor was made. In a comprehensive study by Hallett[32] two types of liquifaction systems were considered: a high pressure nitrogen recycle system and cascade system. The high pressure nitrogen recycle system requires about 46% more energy for compression equipment than the cascade system, and overall, the cascade system offers the best economic potential. The electrical energy required for the cascade system is $q = 4.46$ kw-hr/lb LH_2[33].

As indicated in subsequent section of this analysis, the cascade refrigeration system consumes significant quantities of nitrogen, methane, propane and ethylene. Of particular note is the consumption of 261,400 million standard cubic feet of methane annually. Information obtained, recently, from Washington Natural Gas Company indicates that natural gas in quantities of this magnitude may not be available in 1990 and this eventuality would lead to an alternate liquifaction plant (like the high pressure nitrogen recycle system) and, therefore, to an increase in electrical energy consumption on the order of 50%.

Distribution system delivery efficiency (η_d)

Significant loss is encountered when transferring liquid hydrogen. The National Aeronautics and Space Administration (NASA) experiences a loss of 10% per transfer operation. Although considerable care is taken by NASA in attempting to reduce these losses, it is expected that once liquid hydrogen is made available on a commercial scale, the increased frequency of use of the distribution system, and advanced care and techniques to minimize loss, tied directly to the profit incentive, will reduce this factor to below 10%. Hallett[34] has estimated that this factor may realistically be brought to near 7%. The distribution system delivery efficiency is therefore estimated as $\eta_d = 0.93$.

Storage losses ($f_{h\ell}$)

Losses of liquid hydrogen in storage are due almost entirely to boiloff from heat entering the tanks. Evacuated, perlite insulated, double wall tanks are used to provide the best insulation possible within today's

cryogenic storage technology. Representative values for heat losses and boiloff from 36 inch thick insulated tanks are shown in Table 1.

Table 1

Double Wall Evacuated Perlite Storage System Heat Leak and Boiloff[35]
(36 inch insulation thickness)

Capacity ($lb\ LH_2$)	Heat Leak (BTU/hr)	% Boiloff per day
6×10^5	1.6×10^3	0.034
18×10^5	3.2×10^3	0.023
36×10^5	5.1×10^3	0.018
72×10^5	8.2×10^3	0.015
96×10^5*	10.0×10^3*	0.014*

* Extrapolated from base data

Storage tank size has been selected as 96×10^5 lb LH_2 for each tank. This selection leads to a loss due to boiloff of 0.014% per day, or f_{hl} = 0.00014 tons LH_2 lost per ton of LH_2 stored (Q_s) each day.

Storage capacity

The capacity of the storage system must be sufficient to provide an uninterrupted supply of liquid hydrogen in the event of an unforseen, exceptionally high demand and in the event of an unforseen loss of electrical power or another component in the liquid hydrogen production system. The following values have been based on a judgement of the likely maximum outage that might occur and expected peak withdrawal rate:

Subsystem outage	7 days
Withdrawal "flywheel"	1 day
Total days storage	8 days

An estimate of the amount of storage weight for eight days of liquid hydrogen may be estimated from the efficiency factor already determined for the distribution system, η_d, and the average amount of liquid hydrogen fuel required daily, LH_2, as follows:

Average storage per day's usage $= LH_2/\eta_d$

$= 1310/.93$

$= 1409$ tons/day

Quantity stored in tanks, $Q_s = 8$ days x 1409 tons/day

$Q_s = 11{,}270$ tons

Ortho-Para hydrogen conversion loss (η_{op})

At the outlet temperature of the liquifaction process the liquid hydrogen is at a temperature of approximately -430°F. At this temperature, the equilibrium concentration of para-hydrogen is nearly 100%. Since the hydrogen produced by electrolysis is about 25% para- and 75% ortho-hydrogen, a spontaneous conversion to the para- form occurs at a slow rate. The heat evolved during this conversion would cause the evaporation of large amounts of hydrogen in storage unless conversion to the para- form is accomplished in the liquifaction stage. The system used in this analysis employs an ortho- to para-hydrogen conversion stage as the liquified hydrogen leaves the liquifaction plant. This stage is effective in converting 95% of the liquid hydrogen effluent to the para- form. The remaining 5% ortho-hydrogen slowly evolves heat, evaporating approximately 1.25% of the product delivered to storage, therefore, η_{op} is 0.9875.

Liquifaction plant efficiency (η_ℓ)

Losses of gaseous and liquid hydrogen occur from seals and mechanical fittings used in the liquifaction process equipment. In the cascade system a loss of approximately 4% of the incoming gas is anticipated, providing a liquifaction plant efficiency of $\eta_\ell = 0.96$.

Electrical Power Required for Average Liquid Hydrogen Demand (MW_{LH_2})

Substituting the values justified above into the relation developed in Appendix D for MW_{LH_2}, an average figure for power required for liquid hydrogen production is $MW_{LH_2} = 2810$ MWe.

Electrolysis, liquifaction and storage estimates

Sizing and consumable materials consumptions are needed in order to provide the necessary parameters for an economic analysis. Figures are determined in Appendix E for the necessary parameters and are summarized below:

Liquifaction unit size: eight 250 ton/day units

Liquifaction unit consumables:

nitrogen: 21.8×10^3 tons/year

methane: 5.44×10^3 tons/year

(2.61×10^5 MCF/year)

propane: 10.9×10^3 tons/year

ethylene: 10.9×10^3 tons/year

Storage tank size and total capacity:

capacity required (eight days design peak capacity)

= 14,500 tons

storage selected:

four 4800 ton storage tanks

Electrolysis system unit size: eight 250 ton/day units

Electrolysis system feed and cooling water consumption:

water: 1.15×10^6 tons/year

Nuclear electrical generating capacity estimates

Also included in Appendix E are calculations of the required capacity of the HTGR-GT energy source to supply the needed electrical energy for the annual average electrical demand for electrolysis and liquifaction, the design peak demand, and monthly fluctuating estimates based on a projection of the aircraft demand for liquid hydrogen. These values are as follows:

Average electrical demand for liquid hydrogen production	= 2810 MWe
Design peak demand for electricity for liquid hydrogen production	= 3550 MWe
Capacity of three 1500 MWe nuclear generating plants operating at 0.85 power factor	= 3825 MWe

Average electricity excess
available for distribution
to the community = 1015 MWe

The fluctuating projections are summarized in Tables 16 and 21.

As is seen from the above estimates, by selecting three 1500 MWe HTGR-GT nuclear supply systems, only a 275 MWe cushion exists during design peak demand conditions, yet, on the average, a significant amount of electricity is provided to the community.

V. SYNERGISTIC SYSTEMS

By-products produced by the liquid hydrogen producing facility include electricity, heat, and oxygen. In the area immediately surrounding the airport these commodities may be used to significant economic advantage. The uses and capacities for these synergistic applications are the subject of the following sections of this analysis.

Electricity

As observed in the previous chapter, the liquid hydrogen production system is primarily designed to produce sufficient electricity for electrolysis during design peak demand periods. This demand was determined by the criteria that the plant should be capable of meeting a demand 10% greater than that observed historically, or 1.267 times the annual average liquid hydrogen demand (see Appendix E). This design provides an excess of electricity that may be delivered to the community. Since the availability of electricity fluctuates, an analysis of the coincidence of these fluctuations with electricity demand in Seattle is made in Appendix F. In calculations of Appendix F, an extrapolation of Seattle electricity demand is made in order to provide an indication, not only of the absolute requirements, but also of the correlation between the fluctuations in supply and demand. These calculations lead to the conclusion that, by employing the excess capacity of the HTGR-GT complex to supply the City of Seattle electricity requirements in 1990, a significant portion of the city's needs can be accommodated using the anticipated average capacity of 1012 MWe as

compared to the demand average of 1729 MWe. The remaining 717 MWe must be met by alternative sources. Perhaps just as significantly, the seasonal peaking requirements can be ameliorated by approximately 28% and a reduction in the maximum peak-to-valley difference in electrical demand of 11% accomplished. The daily peaking requirements can be easily accommodated by diverting electrical power from electrolysis to Seattle's consumers' needs on momentary notice and the "flywheel" capacity of the liquid hydrogen storage system used to absorb these short term demands.

However, as pointed out in the economic analysis, an anamolous situation with respect to peaking power exists in the Seattle area as compared with areas of the country that do not have liberal amounts of hydroelectric power available[36]. With electrical demands base loaded nuclear, it is likely that cheap peaking power will be available in the future from the hydroelectric capacity available in the Pacific Northwest, thus making the features described above of limited financial advantage and, as seen in the economic analysis, no monetary advantage is taken of the HTGR-GT to provide peaking power. The ability of the HTGR-GT to provide a base load role is significant, however, and is an important asset to the overall concept.

Heat

Heat may be used in two areas: space and process heating applications, and defogging. In many areas of the country, heat available from the power plant may be used profitably for runway deicing. In the Seattle area this application is not appropriate.

Space and process heat

The HTGR-GT complex operating at a power factor of 0.85 and an efficiency of 37% will provide 6513 MWth rejected heat at a temperature of approximately 300°F. The specific advantage of the HTGR-GT over BWR or PWR plants is evident here in that less heat is rejected for the rating and that which is rejected is at a much higher temperature and, therefore, more useful. By locating the plant at the airport, this heat may be transported to surrounding industry for process heating needs and to buildings for space heating needs. In this manner, highly efficient use of heat can be accomplished as demonstrated by a planned community, Tapiola Garden City, in Finland[37]. This community is built around a combined electrical power and heating plant achieving an overall efficiency of 80.8% (including line losses), while the electrical generating efficiency is only 25%. This illustrates the practicality of applying exhaust heat to community use. It must be pointed out, however, that the amount of heat used by this experimental community is only 22.7 MWth and it remains to be shown that the quantities of heat produced by the power plant under consideration in this study can be effectively used in the surrounding area.

The calculations and discussion included as Appendix G show that 6513 MWth energy can very conceivably be productively utilized in the area surrounding the Seattle-Tacoma airport. Four specific arguments are presented: that there is a large potential market for low temperature (200-300°F) heat[38] as shown in Table 22; that about 50 large district heating systems are in use today[39]; that the amount of energy exhausted represents only a small fraction of the consumption in the State of Washington in areas that might be appropriate; and finally, that large

process heat consumption by single plants could easily accommodate the amount of rejected heat anticipated (Dow Chemical Company has entered into a contract with the Consumer's Power Company for process heat to be generated by Consumer's Power Companys' Midland plant. The amount of heat purchased is approximately 20% of the amount that will be available from the project under study in this analysis)[40].

Although the potential for effective utilization of the anticipated amount of rejected heat is present, the fact remains that, to date, consumption on this scale has not been met in practice. In order to provide a degree of conservatism, a utilization factor of 70% is assumed to be practical for the available heat and this figure is used in subsequent portions of this analysis.

Defogging

The effective dispersal of warm fogs has not been accomplished in practice on a commercial scale, although attempts to do so with heat date back to 1940[41]. Recently, however, experiments carried out at Vandenberg Air Force Base indicate that nearly 90% of the low visibility conditions that occur at airports may be alleviated sufficiently to allow aircraft landings[42]. Appendix H provides a discussion and Table 24 the conclusions of this experiment, along with speculation on a possible array design for use at the Seattle-Tacoma airport that is sized to be approximately three times that of the array used in the Vandenberg experiments with respect to the total amount of heat supplied to disperse the fog.

Table 25 provides an indication of the frequency and direction of fogs occuring in a selected year at the Seattle-Tacoma Airport. From these observations, it is evident that a single installation at the north end

of the runway at Seattle-Tacoma airport will provide coverage at least 75% of the time that fogs occur.

The amount of heat necessary to supply this array is 1.59×10^9 BTU/hr (470 MWth) during operation. Since this amount of energy represents only 7.2% of that exhausted by the nuclear power plant, a negligible effect on consumers of rejected heat is anticipated.

The terrain off the northern end of the Seattle-Tacoma runways is shown in Figure 5. The majority of the 318 air heating units (exhausting about 5×10^6 BTU/hr each during operation) will have to be mounted on towers ranging up to 150 feet maximum in order to deliver the heat at runway level.

It is apparent that a significant potential for gain from defogging is possible at the Seattle-Tacoma airport using a design similar to that described above. More research into this method of defogging as applied to the Seattle-Tacoma airport prior to implementation would be required however.

Oxygen

Approximately 7.92 tons of oxygen is produced for each ton of hydrogen. This sizeable quantity of high purity oxygen can be used for numerous commercial and municipal applications and should prove to be a significant benefit from this project.

No specific design for the storage of oxygen is included in this analysis, however, and it is assumed that the customers will provide the necessary machinery and transportation for needed quantities. That not sold will be directly exhausted to the atmosphere.

VI. ECONOMIC ANALYSIS

Introduction

It has been shown that the electrolytic production of hydrogen, liquifaction, storage, and distribution to aircraft is within today's technology. Additionally, it has been reported that the use of liquid hydrogen in aircraft is feasible and offers particular advantages along with some disadvantages. In the final analysis, liquid hydrogen will be used only if the advantages realized outway the costs incurred over the present fuel or some other alternative. The analysis technique selected for the proposed system is that known as "Benefit-Cost Analysis". Additionally, since the most common indicator demonstrating the cost of the so-called "hydrogen economy" is a unit cost of hydrogen, a value for this will be determined.

Benefit-Cost Analysis - General

The benefit-cost framework for economic analysis has been employed extensively since World War II to evaluate programs intended to increase social welfare in the U.S. in order to lead to correct choices among alternative investment opportunities[43]. Benefit-cost techniques have been applied to large public investments in transportation, urban renewal, education, and public health. Simply stated, this method is used to inspect the benefits and costs derived from a given investment in an activity that will produce future goods and services. The value of the goods and services provides the quantitative measure of these benefits. The amount of the investment provides the quantative measure of the costs. Provided that the costs and benefits are correctly measured, an investment is warranted if

the benefits accrued exceed the costs incurred. Procedures used to determine the relative magnitude of costs and benefits include the present worth method, rate of return method, benefit-cost ratio method and the annual cost method[44]. For this paper the benefit-cost ratio has been selected since it leads to a relatively simple relation useful for comparison with a single alternative such as is appropriate in this case. The benefit-cost ratio is defined as follows:

$$\text{BCR} = \frac{\text{Present worth of project benefits}}{\text{Present worth of project costs}}$$

A benefit-cost ratio greater than one will indicate a greater worth for the proposed project than for continued use of the alternatives replaced. It is important to note, however, that the mere determination of a benefit-cost ratio exceeding one is not sufficient to conclude that the set of selected alternatives (including liquid hydrogen fuel) should be pursued. Other alternatives, that may include synthetically produced liquid natural gas[45] for example, may be more attractive economically and should be subjected to a similar analysis.

Costs and Benefits

Benefits

Anything good that happens as a result of a project can be loosely categorized as a benefit. Of all benefits, direct primary benefits[46] can be considered as those benefits the project is specifically intended to produce. In the case of the project under consideration, these include only those benefits that lend themselves to quantitative analysis. Two approaches to quantifying direct primary benefits may be utilized: market

value, and the cost of producing the same output in an alternative manner. In the case at hand, the market value of the product is appropriate if the market value used is that of the equivalent amount of fossil jet fuel anticipated to meet future demands. This assumption further implies that the subsequent reduction in the price for fossil jet fuel due to the decrease in demand is not significant. This is a reasonable assumption considering that aircraft consume only 3.2% of the total energy used in the United States[47], and utilization by wide body aircraft represents approximately 80% of that number in the year of project implementation, 1990[48]. Likewise, the market value for other direct primary benefits: electricity, space and process heat, defogging, and oxygen will be used in the analysis. Other categories of benefits are: indirect primary benefits, land-enhancement benefits, secondary benefits, employment benefits, income-redistribution benefits, and intangible benefits. Some of these could be significant as associated with the project proposed. Adequate quantification of these types of benefits is difficult, tedious, and very speculative[49]. For these reasons, such benefits will be considered subjectively.

Costs

As in the case of benefits, anything that will have to be sacrificed in order to implement a project can be categorized as a cost. The most obvious cost would be that of project installation: construction cost, engineering and administration cost, right-of-way cost, operation and maintenance cost, and more minor costs. In the project under consideration costs include the aforementioned categories for the nuclear power plant, electrolysis plant, liquification plant, liquid hydrogen storage system, space and process heat distribution system, and the defogging system. It is these costs

that are included in the denominator of the cost benefit ratio.

In addition to project installation costs, associated costs required to utilize the project output, costs for additional schools and roads to serve a potentially more intensive land use may be incurred. Additionally, induced costs that may be incurred whether or not the sponsoring agency has a legal obligation to pay damages must be evaluated. As benefits other than direct primary benefits are difficult to measure and quantify, associated and induced costs require detailed and extensive analysis and lie beyond the scope of these estimates for quantitative treatment. Such factors, as in the case of benefits, will be treated subjectively. It should be noted that costs other than project installation costs are conventionally treated as dis-benefits, and are included in the numerator of the cost benefit ratio by subtracting them from benefits[50].

Cost of Hydrogen

Many articles have provided as many estimates of the cost of liquid hydrogen. The cost of hydrogen will be determined as an outgrowth of the cost benefit analysis, and the figure determined will be based on the cost of producing the energy required for electrolysis, liquifaction, storage and distribution of the hydrogen as well as the capital and operating costs of the hardware associated with these plants. Credits for space and process heat, defogging, oxygen, and electricity peaking power will be applied to determine both a price in terms of liquid hydrogen weight delivered to aircraft, and in terms of liquid hydrogen energy content.

Present Worth

In order to determine the value of a future investment a means for expressing future costs and benefits in terms of present monetary quantities is needed. This concept is known as determining the present worth of benefits and costs and it is this value that is utilized in the cost benefit analysis under consideration[51]. Initially, it would seem that the present worth of a future investment might be determined by calculating the amount of money that would have to be invested at the interest rate available in order to achieve the amount of money in question at the future date. This is not necessarily the case, however, and this subject will be addressed in the discussion entitled "Social Rate of Discount" that follows. Assuming the correct determination of the social rate of discount, the present worth of a future amount can be expressed quantitatively as follows:

$$PW = \frac{F_a}{(1 + \phi)^a}$$

where:

PW = present monetary value

F_a = monetary value "a" years from the present

a = number of years from the present

ϕ = social rate of discount

Factors such as interest on capital used to finance the venture and escalation in the costs of construction and maintenance must be considered in the determination of F_a.

Interest

The financing of any project involves the raising of funds to buy construction materials, design the facility, pay administrators and laborers, and numerous miscellaneous items. Sizeable projects in the public sector are normally financed by offering bonds to financial institutions which, in turn, bid at various interest rates depending upon the existing demand for their capital. The directors of the project then select the bid offering the lowest interest rate. These bonds are then offered to investors by the financial institutions at the bid rate. The amount of interest is of considerable concern to the project directors since the present worth of interest alone is of a magnitude similar to that of the total direct capital expenditure.

The interest rate (I) that must be paid can be considered to consist of a rate of return available on an essentially risk-free security plus a risk premium. The degree of risk associated with a bond is evaluated by rating organizations such as Moody and Standard & Poor. The more financially secure the company offering the bonds, the lower the risk premium, with long-term government bonds offering the most secure investment and, thus, the lowest rate of return. Municipal corporations may offer tax-free securities and the interest rates are, therefore, correspondingly less than those associated with private enterprise. Since the project under consideration possesses many features that would tend to place it in the category of a municipal corporation, bonds would probably have low interest rates. If the low interest rate were used to analyze the associated costs of the project, a bias in favor of the cost of liquid hydrogen would occur since the tax free feature of the municipal bonds is, in effect,

a public subsidy and a cost in its own right. Another consideration is that the magnitude of implementing similar projects at major airports throughout the country would require a major public (governmental) commitment and therefore, a high degree of security to the public investor would be realized. This implies a small, if not insignificant, risk premium, and that the relatively low, yet taxable, rate of return associated with long-term government securities applies to the financial analysis. For this reason, an interest rate of 8%, approximately the present return on long term (taxable) government bonds, is used in the base analysis. During any given year, then, the cost associated with project installation is as follows:

$$AC = AC_d + AC_{idc}$$

where:

AC = annual cost

AC_d = annual direct costs

AC_{idc} = annual cost of interest during construction

The interest paid during any construction year is based on the accumulated debt to date. Therefore, the following relation holds for the y'th year following project start:

$$AC_{idc} = I \sum_{i=1}^{y} AC_{di}$$

It follows, then that the entire project cost (C) is the sum of the annual costs:

$$C = \sum_{i=1}^{n} AC_i$$

The total project cost (C) is normally considered to be the capitalized cost of a project and, from the preceeding development, it is evident that much of this cost is interest paid on the money borrowed to finance the project during the construction phase. Interest continues to be paid annually on the bonds floated to finance the project as long as these bonds are outstanding, often for as long as 30 to 35 years.

Escalation

The cost of labor and materials increases each year due to a combination of inflation factors and shifting supply and demand relationships. Over even a short time, estimates are difficult and generally unreliable. Most companies utilize the Engineering News Record (ENR) "Construction Cost Index" in preparing estimates of project costs and this index is utilized in this evaluation. Where costs have been found in the literature for a given year they have been updated to the present with the ENR "Construction Cost Index" and then projected into the future at 8% annually. Until recently escalation rates approaching 8% have not been realized. However, it is apparent that the entire national economic outlook is in a period of significant change and higher rates are more likely to persist in the light of significant material and energy shortages that do not appear likely to be relieved. Additionally, local power generation corporate executives tend to favor a figure in the vicinity of 8% in the long term, under the assumption that recent labor settlements approaching 12% annual salary increases are a temporary anomaly attributable to recent perturbations in the national economy as a result of excessive inflationary pressures[52]. A return to lower rates in the future is, therefore, probable. Recent

indicators of an economic slowdown tend to bear out the likelihood of this possibility. In this analysis the determination of escalation rate, j, is as described above and utilized as follows:

$$C_i = C_o(1 + j)^{i-a}$$

where:

i = year of concern

a = original year for which costs were obtained

Where cost indices are utilized, the relation becomes:

$$C_i = C_o(CI)$$

where:

CI = the appropriate cost index relating year i costs to original year o costs

Social Rate of Discount

As seen in a previous section concerning the determination of present worth, the social rate of discount is utilized, not an interest or escalation rate. In benefit-cost studies the choice of a social rate of discount is a key factor in the ultimate result. It is important, therefore, to develop the distinction between this factor and those previously discussed.

By investing existing resources one can exchange present for future consumption. An individual may do so up to the point where his present need for money is exactly balanced with his desire for future gain through investment. It is reasonable to assume that for each "unit" of present consumption that is sacrificed for future consumption the amount of

future benefit would have to be commensurate with the increasingly heavier sacrifice, and, therefore, a larger rate of return would be required. This loosely phrased concept is termed "marginal rate of time preference"[53]. It is obvious that individuals would have broadly varying preferences, ranging from rates near zero to perhaps 20% or higher. The difficulty in determining an appropriate social rate of discount comes into play in attempting to evaluate the rate of time preference for large populations. Much controversy surrounds such evaluations in the economic community, with rates ranging from as low as 3% to as high as 15% being advocated. It is the concept of time preference, however, that distinguishes social rate of discount from interest rates. It is clear that the social rate of discount cannot be completely divorced from concepts similar to those involved in determining the components of interest rates. In fact, the interest rate on long-term government bonds is often used as a rough estimate of the social rate of discount, since, being relatively risk-free, such bonds represent an acceptable time rate of preference on present investment for large numbers of investors. This figure, presently near 8%, is used in this analysis. A vigorous theoretical treatment of "social discount rate" is complex and beyond the scope of this evaluation[54,55].

Cost Estimates

Nuclear power plant costs

For reasons previously outlined, the gas-cooled reactor type (HTGR) has been selected for this analysis. Although well within today's technology no HTGR-GT (gas turbine) plants have been built or sold. Private

discussions between the General Atomic Company and local utilities have led only to the claim that this complex would be competitive with PWR and BWR plants of comparable size. Although contractor prices are not available directly, information from a local utility has led to the estimate that the HTGR-GT is "competitive to within 5%" of PWR's and BWR's of comparable size. This estimate is therefore combined with the best available, detailed information of the Washington Public Power Supply System Nuclear Project No. 3, a pressurized water reactor supplied by Combustion Engineering Corporation, turbine generator supplied by Westinghouse Corporation, architect-engineering services supplied by Ebasco Services Corporation, and R. W. Beck and Associates as consulting engineers. These estimates are adjusted to meet the anticipated requirements for location underground in the vicinity of Seattle-Tacoma Airport. Details of this cost estimation are included in Appendix I for three 1500 MWe HTGR-GT units. These estimates lead to the present worth values shown in Table 2.

Electrolysis plant costs

The capacity of the electrolysis plant was based on an efficiency of 83%, which is considered reasonable with expected progress in improving large scale electrolysis units[56]. Cost estimates were determined in detail by Hallett, et al[57], and these 1967 estimates are updated to 1974 costs as shown in Appendix J. The ENR "Construction Cost Index" is used to place Hallett's 1967 Los Angeles cost in terms of 1974 Seattle costs. Included in the estimates are capital, interest, operating, and consumable (feed water and cooling water) costs for eight 250 ton per day capacity units. The electrolysis plant cost summary is given in Table 3.

Table 2

Total Present Worth of Three 1500 MWe HTGR-GT Systems Sited Underground at Seattle-Tacoma Airport, and Operating Over a 30-Year Span (1974 dollars)

Capital cost	$2,005,000,000
Fuel costs	825,000,000
Operation and maintenance	303,000,000
Administrative and general	81,000,000
Insurance	111,000,000
Total interest on debt (other than capitalized) @ 8% for 30 years	1,805,000,000
Total less underground siting costs	5,130,000,000
Underground siting	921,000,000
Total	$6,051,000,000

Table 3

Electrolysis Plant Costs

Cost Categories	Present Worth, 1974
Capital	$320,000,000
Interest	289,000,000
Operating	588,000,000
Feed and cooling water	11,000,000
Total	$1,208,000,000

Liquifaction plant costs

Liquifaction plant costs are based in part on the data by Hallett[58] and updated to 1974 Seattle costs using the same procedure as that for the electrolysis plant by employing the ENR "Construction Cost Index." The cost of consumables employed in the liquifaction plant, however, are considered to be subject to more extreme escalation than capital and operation costs. For this reason 1974 costs were obtained from local suppliers where possible. Where reliable data could not be obtained, because of the proprietary nature of this data, 1967 costs are doubled. The cost summary for eight 250 ton per day liquifaction units as determined in Appendix K is given in Table 4.

Table 4

Liquifaction Plant Costs

Cost Category	Present Worth 1974
Capital	\$300,000,000
Interest	271,000,000
Operating	363,000,000
Consumables	
CH_4 - Methane	11,000,000
N_2 - Nitrogen	8,000,000
C_3H_8 - Propane	16,000,000
C_2H_4 - Ethylene	52,000,000
Total	\$1,021,000,000

Liquid hydrogen storage costs

From the engineering estimates, it is determined that four 4800 ton, double wall, evacuated pearlite insulated tanks are required. Cost estimates for these tanks are extrapolated from data by Hallett (1967). In Appendix L, an exponential cost scaling factor is determined by using data for other sized tanks and is then applied to the four tanks sized to accommodate the eight days storage that is prudent for liquid hydrogen. The resulting cost estimates are given in Table 5.

Table 5

Liquid Hydrogen Storage Costs

Cost Category	Present Worth 1974
Capital	$ 63,000,000
Interest	57,000,000
Total	$120,000,000

Space and process heat distribution costs

Large amounts of rejected heat from the thermal HTGR-GT cycle will be available for commercial and residential use. In fact, this energy will undoubtedly be used, if not directly as heat to surrounding industry and residential areas, then as source of electrical energy through the use of a bottoming cycle. Analysis of the latter case lies outside the scope of this evaluation. Instead, it is assumed that an industrial and residential complex uses 70% of the energy available. Smaller scale precedents

exist for this assumption, both in the United States and abroad. Tapiola Garden City, Finland, is a planned community incorporating a district heating and electricity generating system[59]. This prototype is used for the estimates contained in Appendix M. It should be carefully noted that both the size extrapolation involved in this estimate and the circumstances of its construction do not directly parallel the synergistic concept herein explored. However, it is one of the closest realizations to the practical utilization of rejected thermal energy in a premeditated adaptation found in the many documents researched. The Tapiola Garden City arrangement is designed to supply community needs rather than industrial needs. This system is fossil fueled and would not need to bear the safeguards scrutiny that would be necessary for such a system with a nuclear source. The commercial application of interest is the Midland Nuclear Plant operated by the Consumer's Power Company. This plant was built to provide process steam to the Dow Chemical Company facilities located across the river from the plant, in addition to electrical energy to the Consumer's Power electrical grid. The steam supplied to Dow is at a pressure of 100 psi, corresponding to a saturated temperature of near 330°F. This quality of process heat is entirely feasible at the high sink temperatures of the HTGR-GT. The amount of heat rejected by the HTGR-GT complex under study is only four times that provided by the Midland Plant (considering the HTGR-GT rejected heat utilization at 70%). Considering these factors, cost estimates are based on extrapolations for a district heating system fashioned after the Tapiola Garden City plan, even though the amount of heat available from the HTGR-GT complex would significantly exceed residential use. Any portion employed for process heat should bring any combined cost to less than that

for a strictly residential system because of a more direct and concentrated distribution.

The present worth cost summary for this system is calculated in Appendix M and summarized in Table 6.

Table 6

Space and Process Heat Distribution Costs

Cost Category	Present Worth 1974
Capital	$297,000,000
Interest	268,000,000
Operating	380,000,000
Total	$945,000,000

Defogging system costs

As shown in the engineering feasibility studies, defogging at the Seattle-Tacoma Airport seems both feasible and economically attractive in view of the assumed number and duration of delays caused by fog. Unfortunately, no data was located that corresponds to the type of defogging system envisioned to be compatible with dry air exhaust from an HTGR-GT nuclear supply system. A conservative estimate has been employed which is based on a cost three times that of a single cooling tower of identical capacity. The details of this estimate are included in Appendix N and the summary of present worth costs is presented in Table 7.

Table 7

Defogging System Costs

Cost Category	Present Worth 1974
Capital	$6,000,000
Interest	5,000,000
Total	$11,000,000

Benefit Estimates

Fuel benefit

Existing prices of jet fuel are difficult to obtain due to the proprietary nature of contracts let by the major suppliers to the major air carriers. However, unofficial but reliable information was obtained. 1974 prices for aircraft fuel paid by the major carriers was from $.28 to $.29/gallon. Bonded fuel must be used by the carriers on foreign flights and this fuel costs approximately $.60/gallon. These prices represent significant escalations over 1973 costs. The 1974 price seems to be stable and, barring further step jumps in the price of oil, should escalate with the economy in the near future. However, the plant under study is planned for the year 1990 and therefore many unforseen factors could enter into the price of jet fuel by that date. Most long-range oil reserve studies indicate that within the next 15 years this particular energy resource could become very scarce at present consumption rates[60]. Only natural gas seems more likely to be depleted in the relatively near future. For the purposes of the estimates under the scope of this study, attempts to

determine the degree of escalation that will be encountered by 1990 are not made since the future remains too unpredictable in this respect. Instead, today's prices are extrapolated at 8% to 1990. This approach is probably very conservative, with any escalation greater than 8% producing proportionately greater benefits for alternative fuels, hydrogen in particular. Another section of this report deals with the sensitivity of the cost benefit ratio to greater rates of escalation of fossil jet fuels.

Estimates of the quantity of fuel required at the Seattle-Tacoma Airport in 1990 have been calculated in Appendix O and result in a present worth of fuel in 1974 of $3,780,000,000. This estimate does not account for a fractional displacement of the far more expensive bonded fuel for foreign flights. Calculations for various fractions of fuel required to be bonded fuel are listed in Table 8.

Table 8

Fuel Benefits

Percent of jet fuel used for bonded flights	Present Worth 1974
0%	$3,780,000,000
10%	4,230,000,000
20%	4,590,000,000
30%	4,980,000,000
50%	5,820,000,000

Electricity benefit

Today's prices for electricity in the Pacific Northwest are not considered representative of the price anticipated in 1990, since today's needs are met primarily by very inexpensive hydroelectric power. This source of power has reached maturity, however, and further significant expansion is not presently foreseen. The present worth calculations are therefore based on what is expected to be the "marginal" cost of electricity; that is, the incremental cost for the sources expected to meet the need in 1990.

Seattle City Light has made estimates that extend to 1990 and these are enclosed as Table 34. The 1990 cost of the Seattle City Light estimate is de-escalated to 1974 per detailed calculations of Appendix P. The resulting price (cost) is 4.71 mills per kw-hr.

The estimates of Appendix D include a calculation of "excess capacity" that is available for the production of electricity on a monthly basis over that required in the production of hydrogen. These estimates are used in Appendix P to calculate revenue on a monthly basis from the sale of electricity.

The estimates of present worth due to the sale of electricity by the method of Appendix P is conservative since no credit is taken for a very attractive feature of this concept: the ability to supply large amounts of peaking power nearly instantaneously. In today's market, the Bonneville Power Administration charges 90% more for power delivered from September through March than during the remaining months of the year. It might be expected, then, that in 1990 the overall benefits would exceed costs to a degree. Due to the uncertainty involved, however, the conservative figure

is used in these estimates.

The present worth of electricity revenues over the life of the plant in 1974 as calculated in Appendix P is $1,250,000,000.

Space process heating benefits

Space and process heating benefits accrue from the sale of rejected heat from the HTGR-GT plants to residential and commercial consumers. As pointed out previously, precedents exist for both types of heat sales from an electricity generating power plant. Although the quantity of heat produced from the power plant is very large, it is only a factor of four greater than the heat consumed by Dow Chemical Company from Consumer's Power Company's Midland plant.

The value of the benefits accrued is based on two estimates of the cost for an amount of coal that would be required to produce an equivalent amount of heat. The first estimate is based on the cost-benefit analysis of the coal fired alternative to the Trojan Nuclear Plant in northeastern Oregon on the Columbia river[61]. This estimate was based on a cost of $8.00 per ton delivered to the site. Detailed calculations are included in Appendix Q, resulting in a benefit expressed as present worth in 1974 of $1,640,000,000.

The second estimate is based on the price presently paid by the University of Washington for coal. This price reflects the recent (late 1974) step increase in the cost of coal resulting from a catch-up to the recent drasticly increased prices of competing fuel oil and the increased costs incurred from the settlement obtained by coal miners in the recent strike. The 1974 delivered price of coal under this alternative is $17.13

per ton. Note also, that, in this latter case, the heat rate of 12,500 BTU/lb coal is factored in, since the quality of this supply, good grade bituminous from Utah, is superior to the lower grade coal, heat rate 10,000 BTU/lb, a sub-bituminous from Montana, or Wyoming, anticipated by the Trojan alternative. The present worth of this benefit as detailed in Appendix Q is $3,360,000,000.

Fog dispersal benefit

Fog dispersal is a particularly attractive use for rejected heat at the Seattle-Tacoma Airport. Of 39 airports included in a Federal Aviation Administration study, the Seattle-Tacoma Airport ranked fifth from the top in potential benefits[62]. For information, Table 36 is included which lists the data presented in the FAA study for all 39 airports. This information could be used to evaluate other major airports serving wide body aircraft.

The data presented in Table 36 are listed in two columns: one including benefits from the reduction in passenger delays and the other without incorporating this benefit. This was done in the FAA study since the magnitude of the benefit when including the value of reduced passenger delays is large and also due to some controversy over the many methods that can be used for determining this figure. In this study the fog dispersal includes the benefit from reduced passenger delays since it is probably the most important benefit and it represents a conscientious effort to quantify this particularly difficult primary factor.

From the estimates of Appendix R it is determined that the present worth of the benefit from fog dispersal is $94,000,000.

Oxygen benefit

The market price for oxygen cannot be determined for quantities that will be produced as a by-product from the electrolytic production of hydrogen. Only limited quantities of high purity oxygen are sold presently and the introduction of quantities as large as 4.31×10^6 tons per year from this single electrolysis complex would provide a significant perturbation in the supply and demand structure. On the other hand, it is unlikely that such large quantities of this high purity gas would not be utilized, albeit for uses not requiring the quality of oxygen produced. A rough estimate is provided in Appendix S by assuming that the revenue that will be attracted is approximately equivalent to the cost of manufacturing oxygen using present day air liquifaction technology. This cost has been found to be approximately $6.00 per ton[63]. This leads to a present worth of annual oxygen revenues over 30 years of $775,000,000.

Costs and Benefits Summary

Costs and benefits as calculated and discussed in the preceding paragraphs and Appendices I through G are summarized in Table 9.

Table 9

Costs and Benefits Summary

Costs: Present worth, 1974	
Nuclear power plant	$5,130,000,000
Underground siting	921,000,000
Electrolysis plant	1,208,000,000
Liquifaction plant	1,021,000,000
Liquid hydrogen storage	120,000,000
Space and process heat distribution	945,000,000
Defogging system	11,000,000
Total	$9,360,000,000
Benefits: Present worth, 1974	
Liquid hydrogen aircraft fuel	$3,780,000,000
Electricity sales	1,250,000,000
Space and process heat sales	1,640,000,000
Fog Dispersal	94,000,000
Oxygen Sales	775,000,000
Total	$7,540,000,000

The above figures have been rounded in the totals to three significant digits.

Note that the figure used for the benefit accrued from the sale of space and process heat is based on the figures for the cost of coal used by Portland General Electric when studying a coal fired alternative. If recent figures obtained from the physical plant department of the University of Washington are used instead, the total benefits become $9,290,000,000, an increase of $1,750,000,000 over those tabulated above.

Another consideration in interpreting the above data is the speculative nature of the value of oxygen sales. In the literature on the production of hydrogen by electrolysis[64] credit is seldom taken for the sale of oxygen and it is assumed that it is merely wasted to the atmosphere. This may be necessary in 1990, but more probably oxygen would be utilized by nearby industry or perhaps in sewage processing. In any case, if no credit is taken for the production of oxygen, the total benefits become $6,770,000,000. It is further assumed in this analysis that oxygen distribution costs are borne by the consumer and therefore no cost is included in the value of total costs.

Benefit-Cost Ratio

The benefit-cost ratio (BCR) of project benefits: the present worth of revenue received from the sale of liquid hydrogen aircraft fuel, electricity, space and process heat, and oxygen, plus the value accrued from the dispersal of fog in the terminal area, to the project costs: the present worth of money required to finance the construction and operating of an underground nuclear energy supply system, an electrolysis plant, liquification plant, liquid hydrogen storage system, space and process heat distribution system, and a defogging system are calculated from the preceding estimates as follows:

<u>BCR = 0.81</u>

This result and a casual inspection of the benefit and cost summary indicate that this particular concept is not economically viable. Benefit-cost ratios for the alternative estimates for the sale of heat based on the price presently paid for coal by the University of Washington and for the elimination of oxygen as an economic benefit are as follows:

<u>Neglecting the benefit from the sale of oxygen</u>:

<u>BCR = 0.72</u>

<u>Including oxygen, with the benefit from sale of heat based on the current price paid by the University of Washington for coal</u>

<u>BCR = 0.99</u>

<u>Neglecting oxygen, with the benefit from sale of heat based on the current price paid by the University of Washington for coal</u>

<u>BCR = 0.91</u>

It is apparent from the above results that under the assumptions that have entered into this analysis the production of hydrogen electrolytically, employing the several foreseeable, quantified, synergistic benefits from a large nuclear plant located underground at the Seattle-Tacoma Airport, is not competitive with the conventional means of providing the benefits at corresponding costs that were considered in the analysis.

Fossil Jet Fuel Escalation Rate Analysis

The calculations in this analysis are based on fuel escalating at a rate of 8% over the next 46 years and upon a social rate of discount (ϕ) of 8%. In all probability, the 8% value assumed for escalation rate is conservative. Over the past two years, under the recent pressures of the oil producing exporting countries (OPEC), the price of oil and jet fuel has more than doubled. The long-term projection of escalation rates remains highly speculative, however. Most indications are that a dwindling oil supply will be the dominant factor in supply and demand pressures on oil prices over the period under evaluation. However, recently some predictions of a surplus of oil by 1985 have been reported in newspaper editorials.

In order to provide a perspective relating the sensitivity of this economic analysis to escalation rates of fossil jet fuel, rates required for the liquid hydrogen alternative to achieve a benefit-cost ratio of one are calculated in Appendix U, for the assumption that only domestic fuel is replaced by liquid hydrogen, and for incremental fractions of bonded fuel replacements up to half the total wide body jet fuel consumption. These figures indicate that if fossil jet fuel escalates at a rate of 9.4% (bonded fuel ignored), under the assumptions incorporated in this analysis, a benefit-cost ratio of one will be achieved. Furthermore, when consideration is given to the replacement of the more expensive bonded fuel, escalation rates needed to achieve a BCR of one are shown in Table 10.

Table 10

Fossil Jet Fuel Escalation Rate to Achieve a BCR of One

Fraction of total wide body fuel consumption that would be bonded	Escalation rate of fossil jet fuel required to achieve a BCR of one
0	9.4%
0.10	9.0%
0.20	8.7%
0.30	8.4%
0.50	7.9%

From the above figures, it is evident that relatively mild increases in the cost of fossil jet fuel as compared to escalation rates of other materials can quickly place the liquid hydrogen concept in a competitive stature.

Cost of Liquid Hydrogen

The cost of liquid hydrogen is often cited in the literature and, for this reason, a value is determined under the assumptions of this particular analysis to relate to some of these figures.

The cost of liquid hydrogen is calculated in Appendix T. The procedure used in apportioning system costs is based on the ratio of nuclear plant capacity dedicated to the production of liquid hydrogen to total capacity and upon the total costs of the unique portions of the system devoted to electrolysis, liquifaction, and storage of hydrogen. Furthermore, the costs of the heat distribution and the defogging system are prorated to hydrogen

costs in proportion to the quantity of heat rejected from that portion of the thermal cycle for the production of liquid hydrogen. Benefits are assigned in the same manner as costs. Net cost is thereby obtained in terms of present worth annually. This value is then divided by the quantity of liquid hydrogen produced actually reaching aircraft to obtain a cost per pound and cost per BTU.

The results are as follows:

<u>Cost of hydrogen</u>: <u>\$ 0.168 per pound</u>

<u>\$ 3.26 per 10^6 BTU</u>

These values compare with a range of \$1.80 to \$3.24 per 10^6 BTU reported in various sources researched[65] in terms of 1973 dollars. Escalating at 8%, this range is found to be \$1.95 to \$3.50 in 1974. The price of commercial jet fuel in 1974 is, in terms of energy cost, \$2.48 per 10^6 BTU domestic (\$.30/gallon), and \$4.96 per 10^6 BTU bonded fuel (\$.60/gallon)[66]. These estimates confirm that, presently, the concept entertained in this evaluation is not economically competitive with fossil jet fuel.

VII. SUBJECTIVE EVALUATION

Introduction

The presentation thus far has included only those costs and benefits considered to be direct, primary, and quantifiable. This necessarily limits the scope of the evaluation. However, it is not feasible, given the resources available in the preparation of this study, to delve more deeply into some of the very complex economic relationships governing such categories as: national balance of payments, work force relocations, weather modification potential and impact, and many other potential economic considerations.

This section is intended to outline a number of quantitative economic considerations by indicating whether a particular impact is considered a net benefit or net detriment.

Net Detriments

National scale

Uranium resources

Uranium resources are not unlimited. At anticipated rates of consumption, significant depletion of readily available yellow cake is anticipated within the next 20 years. Employing nuclear fuels to produce hydrogen for wide body aircraft alone would increase the anticipated demand on nuclear fuel in 1990 from approximately 460,000 MWe to 580,000 MWe worth of capacity or 25%[67]. Although fuel ore costs represent only 3% of the present worth of the total cost of the concept, when considered on a national scale significant impact might be expected particularly if the breeder program continues to suffer technically and economically.

Long-term waste disposal

The economic impact of this requirement cannot be estimated at this point because the method of long-term disposal is still under study. Undoubtedly, significant costs will be incurred that are at present expressed in part as fuel cycle costs within the direct costs of the evaluation. That costs over these will be incurred is probable. Kubo and Rose estimate that this factor could range from 0.24 to 1.06 mill/kwh$_e$ in terms of electricity costs[68]. These values are considered very speculative and the economic impact of this detriment is considered as a subjective factor.

Shipment of radioactive waste

The proposed concept will necessarily increase the shipments of both spent and reprocessed fuel. Technology exists for the safe transport of these materials but they represent a further hazard. The economics involved under normal routine conditions is included in the fuel cycle estimates previously presented in this study.

Liquid hydrogen fueled aircraft safety

Research into the safety of hydrogen fueled aircraft to date does not support the public concern estimated to accompany a hydrogen fuel concept. Like the world's introduction to nuclear power, the Von Hindenberg disaster has sensitized public concern for hydrogen although hydrogen may not be any more hazardous than the natural gas that is used in homes throughout the country. To commence utilization of hydrogen in aircraft will require significant research and testing. This cost cannot be easily estimated and, therefore, is included as a subjective factor to consider in this analysis.

State and local scale detriments

Although some of the concerns presented as national in scale would also be of state or local concern, the following are considered to be primarily of the latter category.

Consumption of water resources

Water is used in significant amounts as feed and cooling water in the production of hydrogen through electrolysis; over 11 million tons per year (7.3 million gallons per day). The cost of this amount of water is included in the economic analysis. However, it must be considered in light of any additional capacity an area may have to provide that might incur costs over those encapsulated in the price of water used in the analysis. It should be noted that the power plant itself, by employing dry cooling, will use only a relatively small amount of water for closed cooling cycles intermediate between the helium gas coolant and the dry air that goes to the cooling towers and defogging system. Some leakage in this system is expected and, provided that the quantity of heat distribution piping is large, a definite demand for makeup water will be encountered.

Exclusion area boundaries

An exclusion area must be established in accordance with the requirements of the U.S. Code of Federal Regulations, 10 CFR 50. The siting of the power plant underground and in a self-contained containment structure has been included in the economic analysis. However, it is not clear whether this is sufficient to permit licensing within the population density existing near the Seattle-Tacoma Airport. This aspect of the concept will require extensive additional investigation and possibly a change in present

federal law pertaining to the siting requirements for nuclear power plants. In any case, an economic impact would be expected in sorting out the legal requirements and in adjusting the physical features to conform to requirements found to exist or that are set in order to accommodate the type of installation postulated in this study.

Hydrogen and oxygen safety

Both hydrogen and oxygen have been handled safely by the National Aeronautics and Space Administration in significant quantities. However, the employment of these highly hazardous materials in large quantities near airports and large numbers of people introduces an entirely different dimension into the safety considerations. Again, the satisfactory solution of these questions will require a significant expenditure of money in research and testing.

Transmission of electricity

High voltage transmission of electricity from the power plant at the airport does not seem prudent considering the presence of low flying aircraft. More expensive underground transmission will be required. This expense has not been explicitly included in the economic analysis and would have to be considered when weighing this alternative to fossil jet fuel.

Aircraft safety in general

Buildings and cooling towers 230 to 260 feet tall could present an obstructional hazard to aircraft and for this reason are located out of the flight paths extending in the direction of the runway to the north. However, in addition to this hazard, turbulence produced by significant

quantities of heat from the dry cooling towers must be evaluated as a potential hazard to aircraft control under certain wind conditions. The evaluation in itself represents an unknown economic cost and the technical or procedural actions that may be determined necessary, another.

Net Benefits

National scale

Conservation of fossil resources

Uranium energy is more plentiful than energy from oil or natural gas. Implementation of liquid hydrogen fuel through electrolysis will significantly reduce the consumption of oil, allowing this resource to be used for other purposes that, by 1990, may provide a greater net benefit than by being used as a fuel for wide body aircraft. If oil resources are reaching the peak of the consumption curve, it is likely that an alternative such as nuclear-produced hydrogen may become far more economical to utilize[69]. The same consideration may be made if coal is employed as an alternative, through coal gasification to produce methane jet fuel, but not of the same magnitude, since recent estimates predict sufficient coal for as much as 200 years at present consumption rates[70]. Environmentally, the immediate impact from utilizing uranium as a source fuel is apparently more attractive despite still unresolved technical problems in determining safe, long-term storage locations for spent radioactive wastes. Coal mining is hazardous underground (as is the mining of yellow cake) and damaging to the environment with strip mining techniques. When burned, it is costly to remove the gaseous and particulate pollutants further adding to what many anticipate as rapidly rising costs for this resource. Freeing coal from

space and process heating demands through utilization of rejected heat from the nuclear gas thermal cycle for other more attractive uses for this particular type of energy or material (like with synthetic hydrocarbon compounds) represents an undertermined benefit that would be realized commensurate with the value of coal for these alternative uses.

Balance of payments

Until recently, the United States has been a net energy exporter; this commodity being responsible for a significant portion of our national wealth. The use of nuclear produced hydrogen will serve to decrease our dependence upon foreign energy resources providing a significant national benefit. The magnitude of such a benefit cannot be computed due to the highly complex and speculative nature of our overall international financial stature today and the many variables that will be encountered in the next 16 years to 1990. As conditions stand today, this particular benefit is a significant argument for a concept such as proposed in this study.

Oil pollution

Although representing a relatively small displacement of the national demand for oil, this concept does nevertheless represent a reduction that could mean a smaller probability of oil pollution from spills in the Puget Sound area.

Fossil fuel storage and waste disposal

The storage of coal requires considerable space as evinced by the reserves stocked by the University of Washington for the relatively modest space heating requirements of this institution. Additionally, storage,

removal and disposal of considerable amounts of ash accompany coal fuel usage. The employment of rejected heat from the nuclear power plant to meet needs otherwise requiring coal or oil eliminate the need for both fuel reserves storage and fossil wastes storage and disposal.

Air pollution

The nuclear plant emits no gaseous or particulate matter nor radioactivity into the air. Fossil fueled energy sources, on the other hand, emit gaseous and particulate matter to a significant extent even with removal equipment which also adds to the expense of utilizing these fuels. The use of rejected heat from the nuclear plant provides a significant, though difficult to quantify, benefit by eliminating these pollutants.

Peaking power

The cost of providing peaking power to electricity consumers represents a significant cost to the electrical power producers in 1974. Steps to relieve this condition may reduce the economic advantage represented by this plant's inherent capacity to provide any conceivable short or extended peaking demand on practically an instantaneous need. The prediction of the value of this capability is further hampered by the transition from the economics of hydroelectric power to a combination of hydroelectric and nuclear power presently in progress in the Pacific Northwest. With nuclear plants being base loaded, hydroelectric stations will be free to provide rapid response to peaking requirements in the future thereby decreasing the potential benefit from the ability to provide peaking power by the nuclear electrolysis/electricity generating combination provided by the concept under study. The ability to provide peaking power would be a significant and probably an estimable benefit for similar

installations at airports throughout the areas of the country that do not enjoy the availability of hydroelectric power in significant amounts.

Electrical transmission loss reductions

The closer an electricity generating plant is to the consumers it supplies, the shorter the transmission distance for the generated power, and the less transmission loss encountered. The concept considered here provides electricity to the City of Seattle, only a few miles from the Seattle-Tacoma Airport location. Implementing similar installations throughout the nation would provide a significant net benefit.

State and local scale

Many of the foregoing benefits can be considered on a local scale and will not be repeated.

Improvement in the local or state economy

Energy produced using nuclear power is economically highly capitalized thereby providing a significant stimulus to the state and local construction and operation forces and the attendant services required by a nuclear facility of this magnitude. The financial resources used for fossil fuels are expended primarily outside the immediate locality, and in the case of the State of Washington, primarily outside the state and, of course, to an expanding degree outside the nation. The benefit that would be accrued is difficult to determine quantitatively due to the interwoven relationships between the dis-benefits accrued in areas where the work force and resources are displaced that may or may not lie beyond local or state boundaries. Qualitatively, however, it is probable that a significant benefit would be realized from a new improvement in the local or state economy.

Esthetics

Fossil fueled energy systems are accompanied by stack emitting pollutants of some significant concentration and by large areas reserved for the receiving, storing and shipping of large quantities of fuel and waste. Characteristic of nuclear power plants is the lack of any requirements to exhaust fuel wastes. By employing dry cooling, the size of cooling towers needed is approximately half the size of those needed for forced draft wet towers. Furthermore, fossil plants require similar cooling requirements as well. By siting the nuclear plant underground and by being free of excess land requirements for storing fuel, a nuclear plant at an airport could be made attractive. By being sightly, the economic value of surrounding property is enhanced, though this advantage is offset to a significant degree by the vicinity of the airport proper and the accompanying noise from aircraft. This benefit is, therefore, not possible to describe quantitatively.

Land conservation

Most of the land required at the airport for the installation of an underground nuclear generating plant and the associated structures under consideration here lies within the boundaries required to be under the jurisdiction of the airport, due to buffer zones and access requirements for aircraft operations. Since the land is already "dedicated", locating nuclear plants within this boundary provides land elsewhere that might have been otherwise required for electricity generation and production of electrical power for remotely produced electrolytic hydrogen. This provides a significant net benefit.

Aircraft and airport benefits

The use of liquid hydrogen in aircraft provides several improvements in the characteristics of aircraft operation. Greater payload to fuel weight ratios are possible[71]. This in turn allows for shorter runways, a safer rapid ascent thereby reducing noise pollution and increasing the land values nearby. Hydrogen fuel is essentially non-polluting, emitting only small quantities of nitrous oxide as a product of combustion that produces mostly water.

Runway deicing

Although the plant design contained in this study does not include provisions for runway deicing, this is an obvious possibility for airports located in areas that endure more severe winter weather than Seattle. Although not appropriate to the specific plant being evaluated at the Seattle-Tacoma Airport, this benefit would necessarily follow upon a national commitment to nuclear produced hydrogen fuel and would be enjoyed on a local scale at the appropriate airports throughout the country.

VII. CONCLUSION

Under the conservative assumptions that have entered into this evaluation, the siting of a nuclear reactor underground at the Seattle-Tacoma Airport to produce electricity for the electrolysis of water to produce hydrogen fuel for aircraft, electricity, heat, and oxygen by-products for commercial and residential consumption has been shown to be technically feasible but not economically attractive when weighing only the quantified costs and benefits.

In projecting costs estimates and evaluating their present worth, escalation at 8%, interest at 8%, and social rate of discount at 8% were used. Increased escalation and interest or a decreased social rate of discount tend to make the present worth of any cost or benefit greater. Since the benefits of a project are accured over many years while the capital expenditure covers only a few years prior to operation, a social rate of discount less than that assumed in this analysis will tend to increase the benefit-cost ratio, favoring the project. In the context of present evaluations by the U.S. Government, a social rate of discount less than 8% would probably be used making this project appear more favorable.

Recent trends in the cost of foreign crude oil result in an escalation of prices far in excess of the 8% used in determining the project benefits. This may be only a short-term trend. However, should the price of aircraft jet fuel increase at a rate exceeding 9.4% annually in the future, the benefit-cost ratio determined from this analysis will exceed one and the project become economically attractive. Since the price of imported bonded fuel used by aircraft on foreign flights is more expensive

than domestic fuel, the fraction of this fuel supply that could be assumed by domestically produced hydrogen fuel tends to favor the project under study. For example, if 30% of the wide body aircraft fuel is used for foreign flights in 1990 requiring bonded fuel, a fuel escalation rate of just 8.4% would make this project exceed a benefit-cost ratio of one.

Many benefits, not easily quantified in monetary terms, may be achieved from implementing this project. These include: the conservation of fossil resources for use in other areas, improving our net balance of payments through a decreased dependence on foreign oil, decreasing possibilities for oil and air pollution, land conservation, and providing electricity peaking power capabilities. Net detriments are apparently outweighed by these potential benefits.

Although this evaluation does not provide justification for implementing liquid hydrogen, produced electrolytically from nuclear power, as a fuel for aircraft, it is apparent that such a concept is on the threshold of economic viability. When considering subjectively evaluated benefits and costs, it may even at this time be attractive. Further investigations into the possible variations surrounding the conditions of this study, as delineated in Appendix V, are warranted.

APPENDIX A

Fuel Characteristics

	Hydrogen	JP-4
BTU/lb (standard conditions)	51,500	18,600
lbs/ft^3	4.42	48.7
BTU/ft^3	227,700	906,000
Same BTU	$3.97\ ft^3$	$1\ ft^3$
Boiling point (°F)	-424	210

APPENDIX B

Liquid Hydrogen Required for Wide Body Aircraft in 1990

Research into the aerodynamic characteristics of liquid hydrogen fueled aircraft by the Boeing Company indicates that larger aircraft harbor significantly more potential than smaller aircraft because the large fuel volume required for liquid hydrogen can be more easily incorporated into the larger aircraft structures without compromising the plane's aerodynamic properties[72]. For this reason, only wide body aircraft are included in this analysis, and it is assumed that the smaller aircraft will either remain on fossil fuel or will convert to an alternate fuel.

In this analysis, first the quantity of jet fuel used by commercial aircraft at the Seattle-Tacoma Airport is determined for 1973. The fraction of this fuel that is used by wide body aircraft is then determined and this value is extrapolated to the year 1990. The quantity of liquid hydrogen required to replace this amount of fuel is then determined and used in sizing the components required to produce this amount of fuel.

Seattle-Tacoma 1973 jet fuel consumption

All commercial jet fuel is delivered to the Seattle-Tacoma Airport through the facilities of the Olympic Pipeline Company. Correspondence with Olympic Pipeline Company has resulted in the following data[73]:

Annual consumption from June 1972 through June 1973 at the Seattle-Tacoma airport averaged 15,246 bbl/day. The average consumption by all aircraft (J) is:

$$J = 15{,}246 \text{ bbl/d} \times 42 \text{ gal/bbl} \times 6.52 \text{ lb/gal/(2000 lb/T)}$$

$$\underline{J = 2087 \text{ T/day}}$$

Fraction of commercially consumed aviation fuel used by wide body aircraft (g_{wb}) is determined as follows:

2nd quarter 1972 passenger seat miles flown by wide body aircraft	= 17,472,216,000 seat miles
2nd quarter 1972 passenger seat miles flown by all commercial aircraft	= 76,472,216,000 seat miles
Total passenger seat miles 2nd quarter 1972 flown by aircraft smaller than wide body	= 58,780,674,000 seat miles

Data for aircraft departures and fuel consumption at the Seattle-Tacoma Airport for an average day, peak month in 1973 are displayed in Table 11[74]. From this information, figures for average consumption in gallons per available seat hour are calculated and displayed at the bottom of Table 11. In order to determine the consumption rate in gallons per available seat mile, the total available seat hour figures must be

multiplied by a weighted average aircraft speed.

Consumption rate for wide body aircraft is then:

$= (11.67)/(v_w)$ (gallons/available seat mile)

Consumption for smaller than wide body aircraft is:

$= (15.02)/(v_s)$ (gallons/available seat mile)

Where v_w and v_s are the weighted average speeds of wide body and smaller than wide body aircraft departing from the Seattle-Tacoma Airport in 1973. Values for v_w and v_s are determined from the data contained in Table 12. Therefore:

v_w = weighted average speed, wide body

= (number departures per day x speed)/(number departures per day)

= 9965/17 = 586 mph

v_s = weighted average speed, smaller aircraft

= 77559/137 = 566 mph

$v_w/v_s = 1.035$

Aircraft fuel consumption nationally is:

Wide Body: 17,472,216,000 (a.s.m.) x $11.67/v_w$ (gal/a.s.m.)

Other: 58,780,674,000 (a.s.m.) x $15.02/v_s$ (gal/a.s.m.)

Table 11

Aircraft Departures and Fuel Consumption - Seattle-Tacoma Airport (Average Day - Peak Month 1973)

Aircraft Type	Seats/ Aircraft	Flights/ Day	Total Flight Seats	Fuel Consumption (gal/st.-hr)	Gal/ Avail-hr
DC-9-10	70	3	210	13.07	2744.70
B-737	95	5	475	11.98	5690.50
DC-9-30	95	6	570	13.07	7749.90
B-727-100	95	32	3040	14.85	45144.00
B-727-200	125	24	3000	14.85	44550.00
B-707/DC-8/ B-320	125	54	6750	15.64	105570.00
DC-8-60	200	13	2600	14.97	38922.00
Total (smaller than wide body)			16645		250071.10
DC-10/L1011	230	7	1610	11.95	19239.50
B-747	330	10	3300	11.53	38049.00
Total (wide body aircraft)			4910		57288.50

Aircraft type	Average consumption (gal/avail seat-hr)
Wide body	57288.50/4910 = 11.67
All other	750071.10/16645 = 15.02

Table 12

Aircraft Departing Seattle-Tacoma Airport
Cruise Speeds[75]

Aircraft Type	Flights/ Day	Best cruise Speed (mph/m)	Speed (mph)	No. Dep. x Speed (# x mph)
DC-9-10	3	559	559	1677
B 737	5	570	570	2850
DC-9-30	6	565	565	3390
B-727-100	32	M. 0.84	595	19040
B-727-200	24	M. 0.84	595	14280
B-7-7/DC-8/ B-320	54	530/544/525	533(avg)	28782
DC-8-60	13	580	580	7540
Total	137	smaller than wide body		77559
DC-10/L-1011	7	M 0.82-0.85/ M 0.85	595(avg)	4165
B-747	10	580	580	5800
Total	17	wide body aircraft		9965

The fraction of commercially consumed aviation fuel used by wide body aircraft (g_{wb}) is:

$$g_{wb} = \frac{2.309 \times 10^{11}/v_w}{2.039 \times 10^{11}/v_w + 8.829 \times 10^{11}/v_s}$$

$$= 2.039/[2.039 + 8.829(v_w/v_s)]$$

$$= 2.039/[2.039 + 8.829(1.035)]$$

$$g_{wb} = 0.182$$

<u>Weight ratio (f_{jh}) of fossil jet fuel to liquid hydrogen jet fuel required to achieve identical payload-distance performance.</u>

Provided that the weight ratio of fossil jet fuel to liquid hydrogen jet fuel required to achieve identical payload distance performance were solely dependent upon the difference in the heats of combustion of liquid hydrogen and jet fuel (51,500 and 18,600 BTU/lb respectively) a value of 2.77 would be achieved. Efficiencies in performance are acquired when using liquid hydrogen that provide aerodynamic advantages which improve this ratio to approximately 4.6 for large aircraft, optimally designed for liquid hydrogen[76], to about 2.96 for a Boeing 747 converted to liquid hydrogen fuel[77]. Various designs for liquid hydrogen fueled aircraft reported in the literature yield figures that fall between these values. Communication with Boeing personnel researching liquid hydrogen fuel has lead to the conclusion that figures much in excess of 3.00 are overly optimistic[78]. For this reason the following value, based on converting a Boeing 747 to liquid hydrogen, has been selected for this study:

$$f_{jh} = 2.96$$

<u>Predicted increase in wide body aircraft fuel consumption from 1973 to 1990 (f_{90})</u>

A recent in-depth aviation demand forecast conducted for the Port of Seattle by Peat, Marwick, Mitchell & Co., San Francisco, California, has been used to determine the probable wide body aircraft fuel needs by 1990[79]. Table 13 that follows is extracted from this report. The data listed for 1993 in this report is used directly for 1990 requirements since the capacity for which the electricity generating plant and liquid hydrogen facilities are built must reflect a certain amount of near term growth, and conveniently, three years is selected.

Table 14 has been prepared from the data of Table 13 and provides a breakdown into wide body and other aircraft types. Summaries are also provided at the bottom of each column of: increase of wide body passenger seats over those of 1973, total flights, total wide body flights, percent wide body flights, increase of wide body flights over those of 1973. The latter figure is directly related to the increase of wide body aircraft fuel consumption (f_{YR}) assuming no significant variation in the fuel consumption characteristics of wide body aircraft over this period.

As seen from the computations summarized in Table 14, the predicted increase in wide body aircraft fuel consumption from 1973 to 1990 is as follows:

$$f_{90} = 10.21$$

The average quantity of liquid hydrogen required by aircraft in 1990 (LH_2) is the product of the 1973 consumption of fossil jet fuel in tons per day (J), the fraction of commercially consumed aviation fuel used by wide body aircraft (g_{wb}), and the ratio of the wide body aircraft fuel

Table 13

AIR CARRIER AIRCRAFT DEPARTURES BY AIRCRAFT TYPE -- AVERAGE DAY/PEAK MONTH

Seattle-Tacoma International Airport - 1973-1993

Aircraft Type	Seats per Passenger Aircraft	1973[a] Passenger	1973[a] All-Cargo	1973[a] Total	1978 Passenger	1978 All-Cargo	1978 Total	1983 Passenger	1983 All-Cargo	1983 Total	1993 Passenger	1993 All-Cargo	1993 Total
F-27/C-640	50	9	--	9	6	--	6	1	--	1	--	--	--
L-188	70	2	--	2	--	--	--	--	--	--	--	--	--
DC-9-10	70	3	--	3	5	--	5	5	--	5	5	--	5
B-737	95	5	--	5	5	--	5	4	--	4	2	--	2
DC-9-30	95	6	--	6	6	--	6	6	--	6	4	--	4
B-727-100	95	32	--	32	32	--	32	25	--	25	10	--	10
B-727-200	125	23	1	24	41	1	42	52	1	53	55	--	55
B-707/DC-8/B-320	125	50	4	54	33	5	38	19	7	26	--	7	7
NSA[b]	180	--	--	--	--	--	--	15	--	15	44	--	44
DC-8-60+	200	8	5	13	7	7	14	5	10	15	--	--	--
DC-10/L-1011	230-250[c]	7	--	7	32	--	32	52	--	52	96	14	110
B-747	300-360[d]	10	--	10	13	--	13	17	--	17	34	4	38
TOTAL		155	10	165	180	13	193	201	18	219	250	25	275
Average seats per passenger aircraft departure		132			150			172			212		

a. Port of Seattle, Revenue Trip Landings, June and July 1973.
b. Denotes new small aircraft of some 180 seats (e.g., 3-engine 7X7, or advanced version of 727-200).
c. Assumed 230 in 1973-1978; 240 in 1983; 250 in 1993.
d. Assumed 330 in 1973-1978; 345 in 1983; 360 in 1993.

Table 14

SEATTLE-TACOMA AIRPORT AIRCRAFT ACTIVITY FORECAST AND PREOICTION OF INCREASE IN WIOE BOOY AIRCRAFT FUEL CONSUMPTION (f_{YR})

Aircraft Type	1973 Seats/AC	1973 Flts/Day	1973 Seats/Oay	1978 Seats/Ac	1978 Flts/Oay	1978 Seats/Oay	1983 Seats/Ac	1983 Flts/Oay	1983 Seats/Oay	1993 Seats/Ac	1993 Flts/Day	1993 Seats/Oay
F-27/C-640	50	9	450	50	6	300	50	1	50	50	0	0
L-188	70	2	140	70	0	0	70	0	0	70	0	0
OC-9-10	70	3	210	70	5	350	70	5	350	70	5	350
B-737	95	5	495	95	5	495	95	4	380	95	2	190
DC-9-30	95	6	570	95	6	570	95	6	570	95	4	380
B-727-100	95	32	3200	95	32	3200	95	25	2375	95	10	950
B-727-200	125	24	3000	125	42	5250	125	53	6625	125	55	6870
B-707/OC-8/B-320	125	54	6750	125	38	4750	125	26	3250	125	7	875
DC-8-60+	200	13	2600	200	14	2800	200	15	3000	200	0	0
Total (smaller than wide body)	---	148	17415	---	148	17715	---	135	16600	---	83	9615
NSA	180	0	0	180	0	0	180	15	2700	180	44	7920
DC-10/L-1011	230	7	1510	230	32	7360	240	52	12000	250	110	27500
B-747	330	10	3300	330	13	4290	345	17	5860	360	38	13690
Total (wide body)	---	17	4810	---	45	11650	---	84	20560	---	192	49110
Total (all aircraft)	---	165	22225	---	193	29365	---	219	37160	---	275	58725
% wide body		10.3	21.6		23.3	39.7		38.4	55.3		69.8	83.6
Increase in wide body flights over 1973		---	---		2.64			4.94			11.30	
Increase in wide body passenger seats available over 1973 (f_{YR})		---	---		f_{YR} = 2.42			f_{YR} = 4.27			f_{YR} = 10.21	

consumption predicted for 1990 to that existing in 1973 (f_{90}) divided by the weight ratio of fossil jet fuel to liquid hydrogen jet fuel required to achieve identical payload-distance performance (f_{jh}) or:

$$LH_2 = J \times g_{wb} \times f_{90}/f_{jh}$$

$$= (2087)(0.182)(10.21)/(2.96)$$

$$LH_2 = 1310 \text{ tons/day}$$

APPENDIX C

Seasonal Variations in Jet Fuel Consumption

Significant variations in the monthly consumption of jet fuel occur as indicated by the following table extracted from the Seattle-Tacoma Airport aviation demand forecast recently prepared for the Port of Seattle by Peat, Marwick, Mitchell & Co., San Francisco, California. Table 15 covers the years 1970 through 1972 and these values will be used directly in predicting the potential variation in monthly fuel demand in 1990 and subsequent years. Table 16 uses the data of table 15 to determine monthly fractions of the annual average fuel consumption. These fractions are also averaged over a three year period for use elsewhere in this report.

Table 15

Monthly Air Carrier Aircraft Operations*
Seattle-Tacoma International Airport 1970-1972

Month	1970	% of 1970 Total	1971	% of 1971 Total	1972	% of 1972 Total
January	9,446	9.1%	8,217	7.2%	8,615	7.9%
February	8,148	7.8	7,665	6.7	8,093	7.4
March	8,985	8.6	8,552	7.5	9,343	8.6
April	8,858	8.5	8,642	7.6	9,351	8.6
May	9,475	9.1	9,975	8.7	10,214	9.3
June	9,749	9.3	10,543	9.2	10,304	9.4
July	8,581	8.2	10,998	9.6	8,611	7.9
August	8,487	8.1	10,993	9.6	8,790	8.0
September	8,144	7.8	10,149	8.9	8,130	7.4
October	8,427	8.1	9,838	8.6	9,361	8.6
November	7,976	7.6	9,376	8.2	9,149	8.4
December	8,138	7.8	9,424	8.2	9,317	8.5
Total	104,414	100.0%	114,372	100.0%	109,278	100.0%

* Itinerant only

Source: Port of Seattle

Table 16

Monthly Fractions of the Annual Average Fuel Consumption
Seattle-Tacoma Airport 1970-1972

	1970	1971	1972	Average
Annual average monthly consumption	8701	9531	9107	9113
Month	fraction	fraction	fraction	fraction
January	1.092	0.864	0.984	0.980
February	0.936	0.804	0.888	0.876
March	1.032	0.900	1.032	0.988
April	1.020	0.912	1.032	0.988
May	1.092	1.044	1.116	1.084
June	1.116	1.104	1.128	1.116
July	0.984	1.152	0.948	1.028
August	0.972	1.152	0.960	1.028
September	0.936	1.068	0.888	0.964
October	0.972	1.032	1.032	1.012
November	0.912	0.984	1.008	0.968
December	0.936	0.984	1.020	0.980

APPENDIX D

Electrical Power Capacity Required for Liquid Hydrogen Production

A description of the basic components of the liquid hydrogen production, storage, and distribution system is provided in the body of this report and a simplified schematic diagram is provided as Figure 4. Each component in the system has a characteristic efficiency (or loss) and these must be combined in an appropriate manner in order to arrive at a capacity required for electrical energy that is used both in the electrolysis and liquifaction stages. (Electrical energy used in the liquifaction stage in support of storage are assumed to be a part of liquifaction energy consumption.)

Distribution System

A quantity of LH_2 tons per day on the average must be delivered to liquid hydrogen fueled aircraft supported by this system. Losses will be encountered with hydrogen, however,[80] and assuming an efficiency of η_d, a quantity of liquid hydrogen is delivered to the distribution system from storage (LH_{2d}) as follows:

$$LH_{2d} = LH_2/\eta_d$$

Storage System

Losses of hydrogen in the storage system occur from two major sources: boiloff from heat entering the storage tanks[81] and from a conversion of ortho-hydrogen to para-hydrogen[82]. Assuming a stored quantity of liquid hydrogen of Q_s tons and a daily fractional loss due to boiloff of $f_{h\ell}$ tons

per day per tons total liquid hydrogen in storage, and a fraction η_{op} of incoming liquid hydrogen to storage ($LH_{2\ell}$ tons per day) that is lost due to boiloff from the heat given off from the ortho- to para-hydrogen conversion reaction, the mass balance through the storage system becomes:

$$LH_{2d} = \eta_{op} LH_{2\ell} - f_{h\ell} Q_s$$

or

$$LH_{2\ell} = (LH_{2d} + f_{h\ell} Q_s)/\eta_{op}$$

Liquifaction System

Hydrogen losses occur within the liquifaction system through seals in rotating equipment and seals connecting stationary piping[83]. Assuming a quantity of hydrogen from the liquifaction plant ($LH_{2\ell}$) and a liquifaction plant efficiency in converting H_2 tons per day of gaseous hydrogen to $LH_{2\ell}$ tons per day of liquid hydrogen of η_ℓ, the mass balance through the liquifaction system becomes:

$$LH_{2\ell} = \eta_\ell H_2$$

or

$$H_2 = LH_{2\ell}/\eta_\ell$$

The overall relation between LH_2 and H_2 with the system as described in the foregoing paragraphs is:

$$H_2 = (LH_2/\eta_d + f_{h\ell} Q_s)/\eta_{op}\eta_\ell$$

Electrical Power Required for Electrolysis

The electrical energy required to provide H_2 tons per day of hydrogen is a function of an electrolysis efficiency, η_e, and the BTU content of

hydrogen produced per BTU of electrical energy expended in producing the hydrogen. Additional conversion factors required are as follows:

h_{H_2} = heat of combustion of hydrogen at standard temperature and pressure = 5.15×10^4 BTU/lb

1 MW = 3.44×10^6 BTU

1 T = 2000 lbs

The amount of electrical energy to produce a ton of hydrogen using electrolysis is:

$$\text{Energy} = \frac{1[\text{ton } H_2] \times 2000\ [\text{lb/T}]\ h_{H_2}\ [\text{BTU combustion } H_2/\text{lb } H_2]}{\eta_e[(\frac{\text{BTU combustion } H_2}{\text{lb } H_2})/(\frac{\text{BTU electrolysis energy}}{\text{lb } H_2})]\ 3.414 \times 10^6 [\text{BTU/MW-hr}]}$$

$$= \frac{1 \times 2000 \times 5.15 \times 10^4}{\eta_e\ 3.414 \times 10^6}\ \frac{(\text{MW-hr electrolysis energy})}{(\text{ton } H_2)}$$

$$= \frac{30.17}{\eta_e}\ (\frac{\text{MW-hr electrolysis energy}}{\text{ton } H_2})$$

Power capacity required to provide sufficient energy to produce one ton a day of hydrogen.

$$= \frac{30.17}{\eta_e} \times \frac{1 \text{ day}}{24 \text{ hr}} = \frac{1.257}{\eta_e}\ [\frac{\text{MW}}{\text{ton/day}}]$$

The amount of electrical energy to liquify a ton of gaseous hydrogen for a process rated at q kw-hr per lb is:

$$= \frac{q\,[\text{kw-hr/lb } H_2] \times 2000\ [\text{lb/T}]}{1000\,[\text{kw-hr}]/[\text{MW-hr}]} = 2q\,[\frac{\text{MW-hr}}{\text{Ton}}]$$

Power capacity required to liquify one ton a day is:

$$= \frac{2q\,[\frac{\text{MW-hr}}{\text{Ton}}]}{24\,[\frac{24\text{ hr}}{\text{day}}]} = \frac{q}{12}\ [\frac{\text{MW}}{\text{Ton/day}}]$$

Power capacity required to produce and liquify H_2 tons per day of hydrogen is:

$$MW_{LH_2} = [\frac{1.257}{\eta_e} + \frac{q}{12}]\ H_2\ [\text{MW}]$$

By substituting the relation previously obtained for H_2 the following relation is obtained:

$$MW_{LH_2} = [\frac{1.257}{\eta_e} + \frac{q}{12}]\,[\frac{LH_2}{\eta_d} + f_{h\ell}Q_s]/\eta_{op}\eta_\ell$$

Where the constants have the following units:

$$1.257\ [\frac{\text{MW-day}}{\text{ton } H_2}]$$

$$1/12\ [\frac{\text{lb-MW-day}}{\text{ton kw-hr}}]$$

Estimate of Monthly Average Power Requirements for Aircraft Fuel and Excess Power Available for Distribution to Meet Local Electricity Demands

The above relation, which provides a means for determining the power required for the production of liquid hydrogen, may be used with the load factors calculated in Appendix C and listed in Table 16 to determine the average monthly power requirements for liquid hydrogen and the excess power available for distribution to meet local electricity needs.

A sample calculation for the month of January is as follows:

LH_2 = (average fuel consumption load factor)(average LH_2 annual demand)

The average LH_2 annual demand was found in Appendix B to be 1310 tons per day and the average fuel consumption load factor determined for January found to be 0.980 (Table 16). Therefore:

$$LH_2(\text{Jan}) = 1310 \times 0.980 = 1284 \text{ tons/day}$$

Substituting the LH_2(Jan) in the relation for required power for liquid hydrogen production (MW_{LH_2}) provides:

$$MW_{LH_2}(\text{Jan}) = \left[\frac{1.257}{0.83} + \frac{4.46}{12}\right]\left[\frac{(0.980)(1310)}{0.93} + 1.6\right]/(0.9875)(0.96)$$

$$= 2754 \text{ MWe}$$

The total amount of electrical energy available from the three 1500 MWe power generating plants operating at a load factor of 85% is:

$$\text{Power available} = 0.85 \times 4500 = 3825 \text{ MWe}$$

Excess available for distribution is the difference between that available and the monthly requirement to meet fuel demands or:

Excess = 3825 - 2754 = 1071 MWe

In this manner, Table 17 has been prepared to provide the monthly average demand for fuel production and the average available for electrical distribution.

Table 17

Monthly Average Power Requirements For Fuel Production and Excess Power Available for Commercial Electricity Distribution

Month	Power for Fuel Production	Excess Power Available for Distribution
January	2754 MWe	1071 MWe
February	2462	1363
March	2776	1049
April	2776	1049
May	3046	779
June	3135	690
July	2889	936
August	2889	936
September	2709	1116
October	2844	981
November	2718	1107
December	2754	1071

The annual average electrical power demand from similar calculations is 2810 MWe.

APPENDIX E

Electrolysis, Liquifaction and Storage Estimates

Average quantity of gaseous hydrogen (H_2) to the liquifaction unit

The quantity of gaseous hydrogen to the liquifaction unit on the average must be calculated in order to provide figures for the associated consumable materials fed to the unit: methane, propane, ethylene, and nitrogen. This figure may be calculated from the efficiencies and losses of the liquifaction and downstream processes as applied to the estimate of liquid hydrogen fuel required by aircraft on the average. Using this technique the following relation is obtained:

$$H_2 = \left(\frac{LH_2}{\eta_d} + f_{h\ell}Q_s\right)/\eta_{op}\eta_\ell$$

Where the symbols used are defined in the system description, Chapter IV of this analysis.

Substituting values as determined in Chapter IV the following calculation is made:

$$H_2 = \left(\frac{1310}{0.93} + 1.6\right)/(0.9875)(0.96)$$

$$H_2 = 1490 \text{ tons/day}$$

Data obtained from the detailed studies of the cascade liquifaction system by Hallett lead to the following material consumption figures[84]:

nitrogen: 0.04 lb/lb H_2

methane: 0.01 lb/lb H_2

propane: 0.02 lb/lb H_2

ethylene: 0.02 lb/lb H_2

Combining these figures to obtain daily and annual average consumption figures yields the data in Table 18 below.

Table 18

Liquifaction Unit Consumption Rates

Consumable	Average Daily Consumption	Average Annual Consumption
nitrogen	59.6 tons/day	21.8×10^3 tons/year
methane	14.9 tons/day (716 MCF/day)	5.44×10^3 tons/year (2.61×10^5 MCF/year)
propane	29.8 tons/day	10.9×10^3 tons/year
ethylene	29.8 tons/day	10.9×10^3 tons/year

Peak quantity of gaseous hydrogen (H_2) to the liquifaction unit

Significant variations from the annual average demand for liquid hydrogen occur. An estimate of seasonal variations in jet fuel consumption is made in Appendix C and monthly to annual average factors are calculated and presented in Table 16. To account for unforeseen variations in aircraft fuel consumption that are not evident in the 1970 through 1972 figures, and to provide a degree of latitude for unforeseen maintenance on the liquifaction equipment, an additional 10% over the calculated peak month is included.

Peak monthly to annual average (July and August 1971) from Table 16 is: 1.152

Factor plus 10% for maintenance contingencies:

$$1.152 + 0.1(1.152) = 1.267$$

The amount of liquid hydrogen that the liquifaction plant will have to be capable of producing is:

$$\begin{aligned} LH_2 &= 1.267 \text{ (annual average amount of } LH_2) \\ &= 1.267\ (1310) \\ &= 1660 \text{ tons/day} \end{aligned}$$

Substituting the above value for LH_2 into the relation developed for gaseous hydrogen at the outset of this appendix provides a value of:

$$\begin{aligned} H_2 &= (\frac{1660}{0.93} + 1.6)/(0.9875)(0.96) \\ &= 1885 \text{ tons/day (design peak demand)} \end{aligned}$$

Selection of plant size

Eight 250 tons per day units are therefore selected in order to provide some room for near term expansion and to allow for maintenance difficulties affecting more than 10% of the liquifaction capacity. Also, the larger liquifaction facilities allow latitude for producing electricity during exceptionally severe demands, such as encountered during the 1973-74 winter when hydroelectric reservoirs in the Pacific Northwest were exceptionally low, severely limiting hydroelectric power generating capacity, and making up the deficit to liquid hydrogen production with the designed excess capacity.

Storage tank estimates

The storage capacity is designed to provide eight days storage during the peak month (which includes 10% over the historical peak). This value is eight times the amount determined under the peak quantity of gaseous hydrogen to the liquifaction unit, less the 4% loss incurred during the liquifaction process, or:

$$\text{Storage capacity} = 8 \times 1885 \times 0.96$$

$$\text{Storage capacity} = 14{,}500 \text{ tons}$$

Storage tank size plays a significant role in the amount of boiloff that may be expected as shown in Table 1. For this reason, as stated in the discussion of storage losses in the body of this evaluation, 96×10^5 lb tanks (4800 tons) have been selected. Four 4800 tons capacity tanks will be required to provide the design stored quantity. It is noted, however, that the selection of four tanks provides significantly more storage than the eight days designed, amounting to over 10 days overall.

Electrolysis system estimates

The electrolysis system must supply the design peak quantity of gaseous hydrogen to the liquifaction plant, 1885 tons per day. Considering the electrolysis plant to consist of integral multiples of 250 ton units after the fashion of Hallett in his detailed study of this system[85], a total of eight 250 ton units is required.

Feed and cooling water required for the electrolysis plant are given as 20.5 lb H_2O per lb gaseous hydrogen[86], leading to an annual consumption of feed and cooling water of 20.5(1490)(365) or 11.15×10^6 tons/year.

Power plant electrical generating capacity

The nuclear electrical generating capacity must be sufficient to supply enough power to the electrolysis plant and the liquifaction plant to accommodate the design peak amount of liquid hydrogen, or 1.267 times the annual average amount of liquid hydrogen required for aircraft. This leads to the following calculation based on the relation developed for electrical power required for liquid hydrogen production in Appendix D.

$$MW_{LH_2} = \left[\frac{1.257}{0.83} + \frac{4.46}{12}\right]\left[\frac{(0.267)(1310)}{0.93} + 1.6\right)/(0.0985)(0.96)$$

$$= 3550 \text{ MWe (design peak demand)}$$

For a nuclear electrical generating plant operating at 0.85 power factor, this amount of power requires an overall capacity of 3550/0.85, or 4175 MWe. On this basis, three 1500 MWe HTGR-GT reactors are selected providing 275 MWe cushion. The excess electrical energy can be used to provide power to the local area. On the average, considerably more electrical energy will be available as follows:

Average electrical demand	= 2810 MWe (see Appendix D)
4500 MWe @ 0.85 power factor	= 3825 MWe
Average available for electricity to community	= 1015 MWe

It is noted, however, that the monthly averages of electricity available for electricity production are a function of liquid hydrogen demand by aircraft. Making calculations on a monthly basis, in a manner similar to that done to find an average amount of electricity available to the community, leads to the values for "Excess Power Available for Distribution" of Table 17 which is included in Appendix D.

APPENDIX F

1990 City of Seattle Predicted Electricity Demand and HTGR-GT Produced Electricity Available

In order to provide an indication of the advantage provided by the excess electricity generating capacity of the liquid hydrogen producing facility, the electrical demand for the City of Seattle is projected to 1990 from data spanning a nine year period (1965-1973), summarized in Table 19[87]. This information, extracted from load graphs, is compared with an estimate of the monthly fluctuating excess electricity available from the liquid hydrogen production complex found in Table 17.

Projections

1990 City of Seattle electricity demands (monthly)

The year 1969 is used as the base year for extrapolating the base load in Seattle to the year 1990 since 1969 centers the span of data used in Table 19. The average load in 1969 computed as the average of years 1965 through 1973 is 751 MWe.

The growth in demand averages 4.05% annually as indicated in Table 19.

Average peak to valley differences (not shown on Table 19) have been computed for each year, with the average in 1969 computed as the average of peak to valley differences from 1965 through 1973 being 317 MWe. The growth in the peak to valley differences has also been computed to be 4.45% annually.

The predicted base demand in 1990 is then:

Table 19

CITY OF SEATTLE - ELECTRICITY DEMAND HISTORY

		Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Average	
1965	Demand (MW)	700	686	640	601	560	523	500	513	551	597	659	740	606	---
	(ratio to average)	(1.16)	(1.13)	(1.06)	(0.99)	(0.92)	(0.86)	(0.83)	(0.85)	(0.91)	(0.99)	(1.09)	(1.22)		
1966	Demand (MW)	750	718	703	640	592	575	539	560	581	655	723	758	650	7.2
	(ratio to average)	(1.15)	(1.11)	(1.08)	(0.99)	(0.91)	(0.89)	(0.83)	(0.86)	(0.89)	(1.01)	(1.11)	(1.17)		
1967	Demand (MW)	777	758	752	698	628	580	540	566	595	697	761	840	683	5.1
	(ratio to average)	(1.14)	(1.11)	(1.10)	(1.02)	(0.92)	(0.85)	(0.79)	(0.83)	(0.87)	(1.02)	(1.11)	(1.23)		
1968	Demand (MW)	860	789	760	752	672	624	598	622	660	768	826	950	740	8.4
	(ratio to average)	(1.16)	(1.07)	(1.03)	(1.02)	(0.91)	(0.84)	(0.81)	(0.84)	(0.89)	(1.04)	(1.12)	(1.28)		
1969	Demand (MW)	1013	920	834	797	705	665	650	653	714	803	862	932	796	7.5
	(ratio to average)	(1.27)	(1.16)	(1.05)	(1.00)	(0.89)	(0.84)	(0.82)	(0.82)	(0.90)	(1.01)	(1.08)	(1.17)		
1970	Demand (MW)	954	885	857	842	736	679	658	612	733	820	882	975	803	0.9
	(ratio to average)	(1.19)	(1.10)	(1.07)	(1.05)	(0.92)	(0.85)	(0.82)	(0.76)	(0.91)	(1.02)	(1.10)	(1.21)		
1971	Demand (MW)	982	940	934	817	714	705	657	645	702	793	878	989	813	1.3
	(ratio to average)	(1.21)	(1.16)	(1.15)	(1.00)	(0.88)	(0.87)	(0.81)	(0.79)	(0.86)	(0.98)	(1.08)	(1.22)		
1972	Demand (MW)	1001	953	873	865	741	718	669	699	750	832	900	1023	835	2.7
	(ratio to average)	(1.20)	(1.14)	(1.05)	(1.04)	(0.89)	(0.86)	(0.80)	(0.84)	(0.90)	(1.00)	(1.08)	(1.22)		
1973	Demand (MW)	1020	940	904	845	782	739	704	728	713	793	902	886	830	-0.7
	(ratio to average)	(1.23)	(1.13)	(1.09)	(1.02)	(0.94)	(0.89)	(0.85)	(0.88)	(0.86)	(0.96)	(1.09)	(1.07)		
		1.19	1.12	1.08	1.01	0.91	0.86	0.82	0.83	0.89	1.00	1.10	1.19		4.05%

$$MWe_{90} = MWe_{69}(1.0405)^{21}$$
$$= 751\ (2.30) = 1728\ \text{MWe}$$

The predicted peak to valley difference is:

$$MWe_{90} = MWe_{69}(1.0445)^{21}$$
$$= 317\ (2.50) = 790\ \text{MWe}$$

The increase in monthly to annual average load factors is proportional to one minus the 1969 load factor times the ratio of the 1990 peak to valley difference to the average annual demand divided by the 1969 ratio of peak to valley difference to annual demand. This increase is then added to one to obtain the 1990 monthly load factor estimates.

$$\text{1990 load factor} = 1 + [1-(\text{1969 load factor})]\left[\frac{MWe_{90}/\text{average } MWe_{90}}{MWe_{69}/\text{average } MWe_{69}}\right]$$

In this method, 1990 load factors are estimated and shown in Table 20.

Table 20

Predicted Electrical Demand Load Factors in 1990 (Seattle)

Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
1.20	1.13	1.09	1.01	0.90	0.85	0.81	0.82	0.88	1.00	1.11	1.21

Table 19 figures are used to multiply the predicted Seattle 1990 base load of 1728 MWe to obtain monthly values for use in Table 21.

1990 HTGR-GT excess electricity available for community consumption

Under the calculations associated with the power plant electrical generating capacity that were accomplished in Appendix D, typical monthly average amounts for the year 1990 were determined and the results displayed in Table 17.

Comparison of electricity demand to excess electrical power available

The values calculated by the foregoing manipulations are compared in Table 21.

A plant that operates at a constant output meeting a constant demand is an ideal situation. A measure of the deviation from such a condition is the sum over a year of the monthly deviations from the average. The sum (absolute values) obtained from column 5 in Table 21 above is 2575 MWe. Over the year, this is the amount of electricity required above or below the annual average. With the addition of electricity from the HTGR-GT in excess of that required for liquid hydrogen production, this value is reduced to the value obtained from the sum of absolute values in column 6 of 1866 MWe for the year. This represents a reduction of 28% and a significant input to the seasonal peaking demand likely to be experienced in 1990. As pointed out in the economic evaluation, it is very difficult to put a monetary value on this reduction in seasonal peaking due to the large amount of hydroelectric power available in the Pacific Northwest coupled with the anticipation that the base load for electrical generation in 1990 will be nuclear powered and that the peaking requirements will be supplied by hydroelectric power[88]. Another evident advantage obtained from the electrical power available from the excess produced by the HTGR-GT is in a reduction of the peak to valley absolute requirements from 674 MWe without the HTGR-GT, to 598 MWe. This represents a reduction of about 11%.

Table 21

Comparison of Electricity Demand to Excess Electrical Power Available in 1990 - Seattle

Month (1)	Estimated Excess (MWe) (2)	Excess Minus Average (MWe) (3)	Estimated Demand (MWe) (4)	Demand Minus Average (MWe) (5)	Column 5 Minus Column 3 (MWe) (6)
Jan	1071	59	2074	345	286
Feb	1363	351	1953	224	-127
Mar	1049	37	1884	155	118
Apr	1049	37	1745	16	-21
May	779	-233	1555	-174	59
Jun	690	-322	1469	-260	62
Jul	936	-76	1400	-329	-254
Aug	936	-76	1417	-312	-236
Sep	1116	104	1521	-208	-312
Oct	981	-31	1728	-1	30
Nov	1107	95	1918	189	94
Dec	1071	95	2091	362	267
Average	1012		1729	|sum|=2575	|sum|=1866

APPENDIX G

Space and Process Heating Applications and Estimates

Space and process heating applications are more readily associated with rejected heat from an HTGR-GT than from a BWR or PWR reactor since the HTGR-GT exhausts heat at temperatures approaching 300°F as compared to exhaust temperatures of around 90 to 120°F for BWR and PWR reactors[89]. This advantage provides the potential for efficient use of rejected heat in addition to the efficient use of fuel by the HTGR (37%) as compared to the PWR or BWR (about 30% for each). For example; if the BWR or PWR are required to produce process heat (normally considered at near 300°F for many applications[90]) a special steam extraction system must be employed to accomplish this efficiently. Using the HTGR-GT, however, exhaust temperatures are sufficiently high for efficient use of this energy for process heat directly and this feature leads to the design possibilities described in the following portions of this appendix.

Heat rejected from the 4500 MWe HTGR-GT complex

The 4500 MWe HTGR-GT complex is anticipated to operate at a power factor of 0.85, providing approximately 3825 MWe to electrolysis and liquifaction demands, and electricity to the community. At an efficiency of 37%, this means that the total amount of heat generated by the plant is 3825/0.37 or 10,338 MWth. Since 3825 MWth are used productively in electrical energy generation, 10,338 - 3825, or 6513 MWth, remain exhausted to the gas turbine cycle sink. With the HTGR-GT this energy is exhausted at a temperature near 300°F as compared to temperatures near 100°F for steam

cycle systems. A survey of potential urban uses of thermal energy from steam plants lead to Table 22 below extracted from a study for waste heat utilization presented in 1972[91].

Table 22

Energy Use Estimates

Energy Component	Supply Temperature*	Estimated 1980 Usage**
Electricity		1
Low Temperature Heat		
Space heat	200°F	1
Domestic hot water	200°F	0.2
Absorption A/C	250°F	1
Water distillation	265°F	0.3
Industry	300°F	0.8
Snow and ice melting	212°F	---
Transportation	300°F	2
Waste heat		
Secondary sewage treatment	95°F	---
Agriculture-aquaculture	95°F	---

* Approximate minimum temperature of transmitted steam or hot water

** Ratio to energy utilized in the United States as electricity.

A surprising feature of the data in Table 22 is the large proportion of useful low temperature heat for use in the transportation sector of the energy market. Preliminary estimates have been made on the performance of steam propelled intra-city busses[92]. The use of hot water at 300°F appeared to result in a vehicle having satisfactory tonage weight and a range of 10 miles. Such vehicles could be developed and made commercial by as early as 1980[93].

Another consideration relating to the potential utilization of rejected heat is that (also indicated in Table 22) district heating systems are not uncommon today. About 50 large systems, the largest being Consolidated Edison's in New York supplying Manhattan with a peak of about 3000 MW of heat, are supplied by extraction or backpressure turbines[94]. With the HTGR-GT, the high exhaust temperatures will likely permit direct use of this heat for space heating needs in the community surrounding the airport.

As evidence of the magnitude of energy consumption potential in the State of Washington, Table 23[95] is provided for comparison with the exhaust heat available from the HTGR-GT.

The amount of thermal heat rejected by this power plant is 6513 MWth, or in units of Table 23, 0.006513 million MWth. Clearly, this is a relatively small portion of the energy consumed in any of the sectors listed and the conclusion reached is that the amount of energy emmitted can be absorbed into the overall energy consumption picture.

A last argument in support of viable rejected heat utilization is the recent contract entered into between the Dow Chemical Company and Consumer's Power Company for process heat to be supplied by Consumer's Power Company's Midland Nuclear Plant[96]. This supply will be provided by

Table 23

Energy Consumption in the State of Washington - 1971

(Millions of MWth)

	Oil	Gas	Coal	Hydro	Nuclear	Total	Percent
Residential	29.0	10.7	1.1	16.7	4.0	77.8	33.4
Commercial		6.6	0.2	7.6	1.8		
Industrial	10.7	30.9	0.7	22.8	5.5	70.6	30.3
Transportation	79.8	--	--	--	--	79.8	34.2
Other	2.4	--	0.1	1.9	0.5	4.9	2.1
TOTAL	121.9	48.2	2.1	49.1	11.7	233.0	
Percent	52.3	20.7	0.9	21.1	5.0		100.0

a steam extraction turbine at approximately 330°F, not much higher than that directly available from the HTGR-GT exhausted heat. This single Dow Chemical plant will consume 3.55×10^6 lb/hr at these conditions and another 0.5×10^6 at a temperature of around 480°F. The low temperature steam corresponds to an energy content rate supplied of 3.98×10^9 BTU/hr, or 1165 MWth/hr. To place this figure in perspective with the amount of exhausted energy, it is seen that only 5.6 times the amount used by this single industrial facility is anticipated from the project under evaluation.

Without entering into specific evaluations and designs for the utilization of rejected heat from the HTGR-GT complex, it is evident that the potential for effective use of this energy is present.

In order to provide some degree of conservatism, it is assumed in the economic evaluation that only 70% of the rejected heat is directly used in space and process heating applications.

APPENDIX H

Defogging Feasibility

The Seattle-Tacoma Airport ranks fifth in the nation in potential benefits from fog dispersal, as shown in Table 36. The availability of relatively high temperature (near 150°F), dry air from cooling units could provide a significant reduction in the amount of fog experienced and a corresponding reduction in fog-related cancellations, delays, and hazards.

Since the 1940's, attempts have been made to use large quantities of heat to clear the vicinity of airport runways of fog. These attempts have met with limited success although possessing the potential for successfully clearing warm fogs[97]. This is likely due to the large amount of heat required to provide significant improvement in visibility.

Recent experiments with warm advection fogs occuring at Vandenberg Air Force Base seem to indicate a significant improvement in results over past experience resulting in the estimates of improving visibility to the landing minimums listed in Table 24[98].

Table 24

Occurance of Landing Minimums Produced by Heating of Vandenberg Advection Fog

Fog Category	Conservative Estimate (%)	Upper Limit Estimate (%)
Extremely heavy	0	20
Moderately heavy	91	100
Medium	100	100

Extremely heavy fog conditions occur only about 8% of the time; therefore, significant improvement can be expected. Wind conditions during fogging conditions are predominantly from the south making a defogging system located at the northern end of Seattle-Tacoma Airport runways effective in dispersing most fogs -- probably even many of the heavy variety. Table 25 summarizes 1971 meteorological data at the Seattle-Tacoma Airport pertaining to fogging conditions[99].

Table 25

Incidence and Direction of Fog at the Seattle-Tacoma Airport in 1971

Month	Hours Fog	Average Direction (°T)	Hours Fog From North	% From North
January	42	154°	3	7.1
February	24	179°	0	0.0
March	17	135°	0	0.0
April	4	105°	1	25.0
May	17	198°	0	0.0
June	14	180°	2	14.3
July	19	207°	4	21.1
August	4	135°	0	0.0
September	17	145°	3	17.6
October	57	168°	32	56.1
November	37	156°	11	29.7
December	54	138°	18	33.3
Total	306	160°	74	24.2

It is evident that most of the fog that comes from the north occurs during the middle autumn weeks. Consideration must be given to whether defogging installations at both the north and the south end of the runways is cost effective as compared to the benefits received from an installation only at the north end of the runway. Clearly, a single installation will provide coverage over 75% of the time; and only a single installation is considered in this analysis.

In the Vandenberg experiments burners were arranged in four rows spaced from 165 to 660 feet from the test tower and ranging from 451 feet for the closest row to 876 feet for the row furthest away. The heat supplied by each row was increased with distance from the tower, a total of 56.0×10^7 BTU/hr being supplied to heat the air[100]. Figure 5 below is a first estimate of an installation appropriate for the Seattle-Tacoma Airport using a total of 318 air heating units utilizing rejected heat from the nuclear power plant. Each unit is rated at a capacity of 5×10^6 BTU/hr, nearly tripling the capacity of the experimental unit employed in the Vandenberg experiments under the assumption that more consistent results in clearing the fog might be attained. This entire design is at best preliminary, but should be an adequate approximation for the purposes of this analysis.

This installation would likely be able to supply sufficient heat to disperse most fogs from southerly directions (090 to 270°T). The total amount of heat required by this installation is 1.59×10^9 BTU/hr when in operation, or equivalently, approximately 470 MWth in rejected heat. This represents only 7.2% of the heat rejected from the power plant and is not likely to significantly affect other consumers of this energy when in operation.

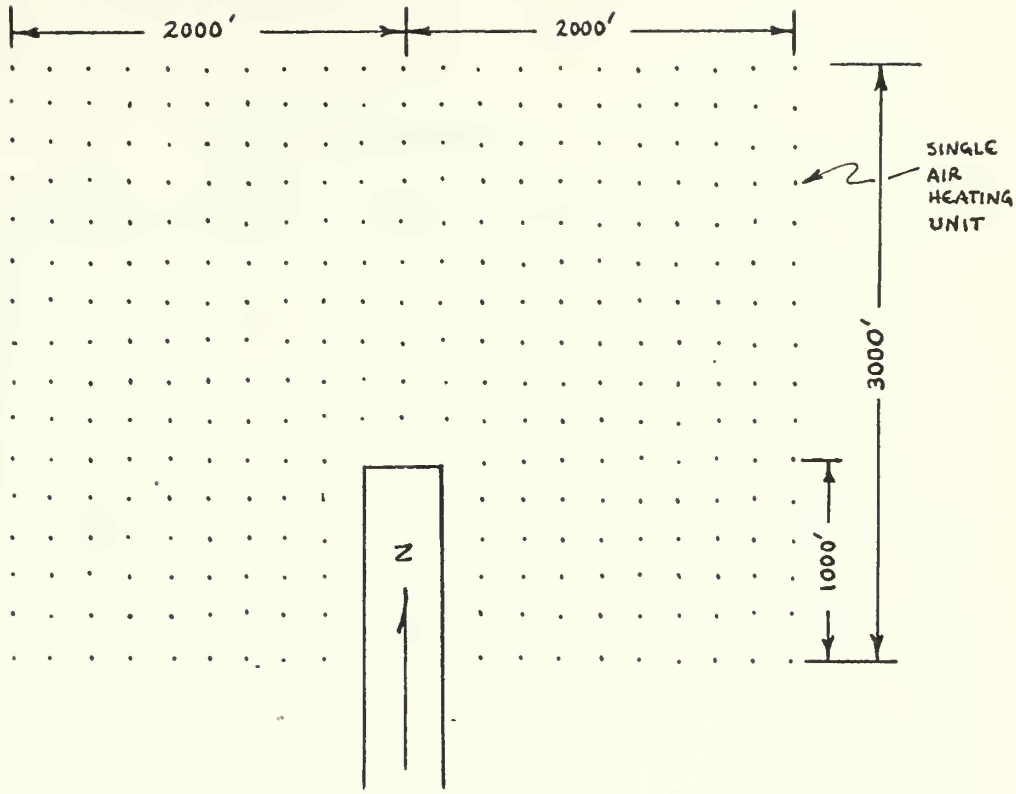

Figure 5
Proposed Seattle-Tacoma Airport Defogging Array

The terrain off the north end of the Seattle-Tacoma runway requires a number of towers in order for the heat to be emitted at the approximate height of the runway. The economic estimates, therefore, are designed to provide an approximate factor to accommodate this cost. Figure 6 is a profile view of this terrain[101].

The maximum elevation difference found from Figure 6 is 150 feet, thus the highest tower required for heat distribution for the fog dispersal system.

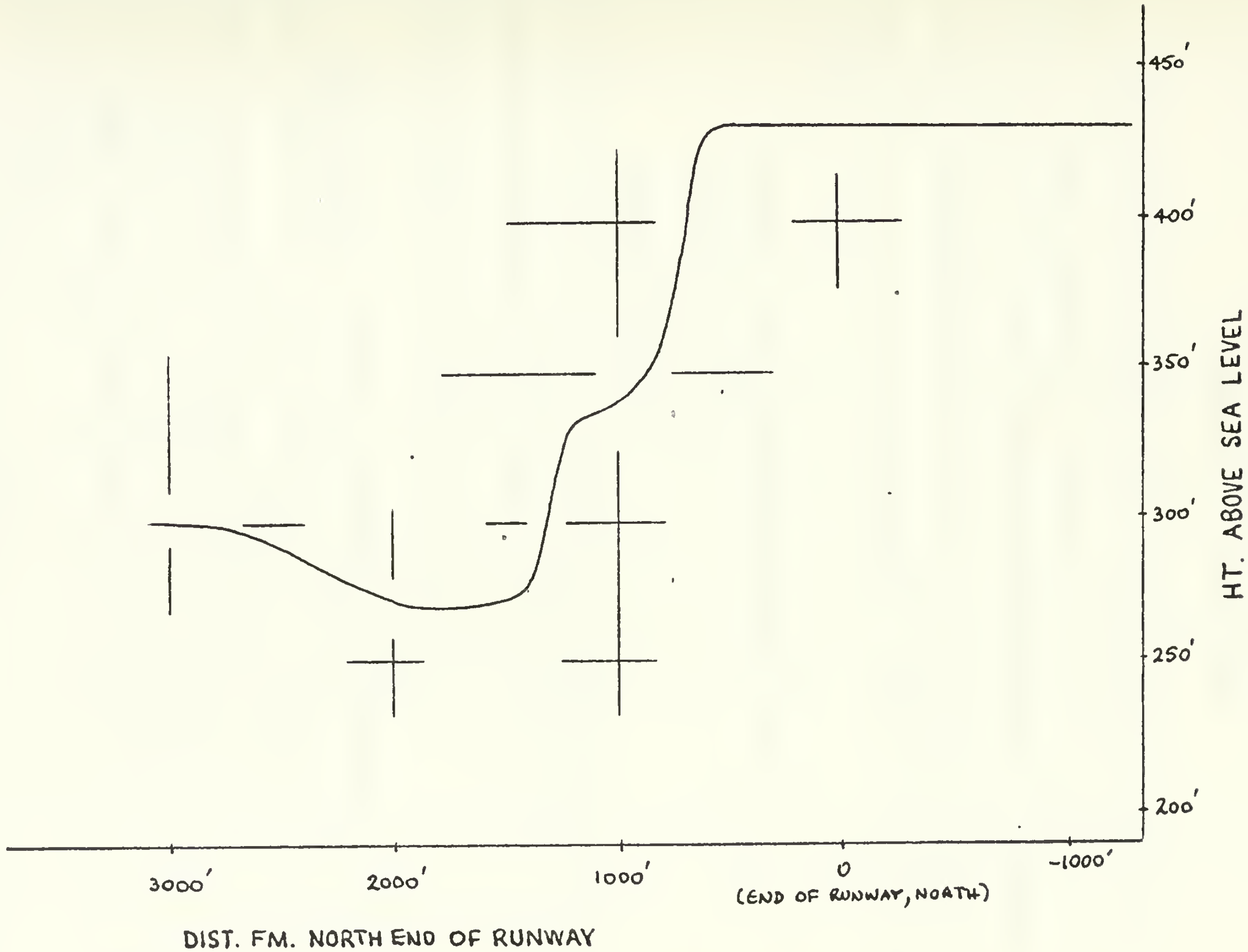

Figure 6

Seattle-Tacoma Runway North Approach Profile

APPENDIX I

Nuclear Power Plant Costs

1. "Washington Public Power Supply System Nuclear Project No. 3 (WPSS #3) Updated Construction Budget and Supporting Detail," dated 30 September 1973, for one 1200 MWe PWR (Combustion Engineering) is used as the cost base upon which the cost of the HTGR-GT system will be estimated assuming that its cost will be 5% greater. WPSS #3 costs are categorized as follows:

   Nuclear Power Plant Direct Construction Costs

   Owners Direct Costs

   Financing Expenses

These costs are detailed as estimated on an annual basis for the years of anticipated construction, 1973-1982, with modifications as outlined in subsequent paragraphs and displayed as Table 26.

2. Land & Rights: Based on acquisition of 190 homes at $45,000 per home in 1974, for a total of $8,550,000[102]. Acquisition of additional land requires approximately 620 acres in addition to that owned by the Port of Seattle (57 acres)[103]. Presently, the port of Seattle plans to purchase this property and, therefore, this cost is not directly attributable to the project at hand.

3. Environmental Studies: Cost of $3,000,000 annually over a period of 10 years is assumed based on a 50% increase due to more intricate environs, over similar studies for the Trojan plant in Oregon[104].

Table 26

Nuclear Power Plant Costs

	1973 ($1000)	1974 ($1000)	1975 ($1000)	1976 ($1000)	1977 ($1000)	1978 ($1000)	1979 ($1000)	1980 ($1000)	1981 ($1000)	1982 ($1000)	Total ($1000)
Nuclear Power Plant (WPPSS#3-1200MWe nominal rating)											
Land and Rights*		8550									
Environmental Studies*	300	300	300	300	300	300	300	300	300	300	
Buildings, Structures and Site Work				3700	35700	46200	7600	1700	100		
Reactor Plant Equipment				13150	15440	26860	45440	36610	2500		
Turbine Generator Plant					10100	13700	73900	11900	400		
Accessory Electrical Equipment					1800	10700	14900	6800	800		
Miscellaneous Power Plant Equipment							1500	1500			
Substation							2000	2000			
Nuclear Fuel	1320	1320	1320				4033	22882	3456		
Sales Tax	66	66	66	843	3152	4874	7470	4564	534		
Architect Engineer	2400	6400	7200	7325	6350	4950	4800	3925	1650		
Contingencies					2647	12968	15886	17360	4559		
Subtotal: Direct Construction Costs	4086	16636	8886	25318	75489	120552	177829	109541	14299	300	552936
Owner's Direct Costs											
General and Administration	177	378	393	477	617	844	840	895	853	366	
Project Management	420	925	793	948	1455	2532	3457	4269	4704	757	
Training					21	87	352	210	270		
Consultants	160	77	77	77	77	77	77	77	77	36	
Plant Start-Up							93	1467	992		
Regulartory Fees	51	128	1098	3	3	3	3	1151	74	3	
Insurance	220		173	317	491	496	389	436	513		
Contingency	417	117	350	326	320	265	250		291		
Spare Parts								800	800		
Subtotal: Owner's Direct Costs	1445	1625	2884	2148	2984	4304	5461	9305	8574	1162	39892
Financing Expense	232		2700			2352	4706				9990
Total (Construction, Owner's Direct, Financing	5763	18261	14470	27466	78473	127208	187996	118846	22873	1462	
Cumulative	5763	24024	38494	65960	144433	271641	459637	578483	601356	602818	602818
Interest During Construction (@ 8%)	461	1922	3080	5277	11555	21731	36771	46279	48108	48225	223409
Total Including IDC	6224	20183	17550	32743	90028	148939	224767	165125	70981	49687	826227
Cumulative (IDC Included)	6224	26407	43957	76700	166728	315667	540434	705559	776540	826227	
Costs in 1974 Dollars @ 8%	6722	20183	16250	28072	71467	109475	152973	104057	41416	26844	577459
Cumulative Costs (1974 Dollars)	6722	26905	43155	71227	142694	252169	405142	509199	550615	577459	

* Not included in WPPSS#3 data -- estimated from information from Port of Seattle and Trojan Nuclear Plant Data

4. Total (Construction Direct, Owner's Direct, and Financing) costs are calculated on an annual basis by adding the appropriate subtotals. Interest during construction is not included.

5. Interest during construction is calculated at 8% of the cumulative expenditure to date. Note that this value is an approximation and would actually be determined from the yield bid on bond issues during the construction period less the value of short-term reinvestments.

6. Total costs with interest during construction represents the total outlay required for the years construction activities and includes the sum of Construction, Owner's Direct, Financing, and Interest During Construction costs.

7. Cumulative costs in dollars associated with the year of disbursement provides the figure for which financing is required should the project run from 1973 through 1982. The project under consideration would run from 1981 through 1990. However, since the assumed escalation is 8%, and the social rate of discount is 8%, escalation to the appropriate year of anticipated construction, followed by de-escalation back to a present worth in 1974 dollars at the social rate of discount will yield an identical result, as would de-escalating the 1973 through 1982 values to 1974 dollars at an 8% social rate of discount.

8. <u>Cumulative Costs (1974 dollars)</u>: Represents the present worth of construction outlays including interest during construction from the start of the project to the indicated year at a social rate of discount of 8%. Total present worth is found to be $577,459,000.

9. Equivalent Calculation for a 1500 MWe HTGR-GT: Informal statements by various utility sources indicate that the "HTGR-steam cycle is competitive with PWR and BWR plants of comparable size within 5% of costs." Assuming a 5% greater cost for the HTGR, the following cost for a 1200 MWe HTGR-steam cycle plant results:

$$\text{HTGR-steam cycle (Present Worth 1974) 1200 MWe} = (1.05)(\$577{,}459{,}000)$$
$$= \$606{,}332{,}000$$

Informal statements from various utilities indicate that the predicted cost of an HTGR gas turbine power plant will be the same as that for an HTGR steam cycle plant with a wet cooling tower. Therefore:

$$\text{HTGR-GT (dry cooling) (Present Worth 1974) 1200 MWe} = \$606{,}332{,}000$$

10. Estimate of Cost for 1500 MWe HTGR-GT: According to Mr. H. E. Vann, as reported in "Cost Trends for Nuclear Power Plants," Nuclear News, October 1971, an estimate of larger nuclear power plants can be made by using the quoted size ratioed to the reference size to the 0.8 exponent times the quoted size of the reference plant as follows:

$$\text{HTGR-GT (dry cooling 1500 MWe)} = \left(\frac{1500\text{ MWe}}{1200\text{ MWe}}\right)^{0.8} \times \left[\begin{matrix}\text{HTGR-GT dry cooling}\\ \text{1200 MWe}\end{matrix}\right]$$
$$= \left(\frac{1500}{1200}\right)^{0.8} \times \$606{,}332{,}000$$
$$= \$724{,}834{,}000$$

11. Cost Estimate of Three 1500 MWe HTGR-GT Units:

A. A. D. Little has reported a savings of approximately 5% for twin nuclear generating units[105].

B. Pamphlet "HTGR Nuclear Steam System and Fuel Supply" issued by General Atomic Company states: "A twin HTGR installation can offer advantages more significant than those of other fossil or twin nuclear plants[106]."

C. Because of the small size of the HTGR-GT combination over the HTGR-steam cycle plant, it is likely that an even further reduction in cost might be expected. However, in view of a conspicuous lack of objective, quantitive information, a 5% savings will be used for this analysis.

D. The cost reduction realized by utilizing a three unit complex is estimated by determining the value (x) in the following empirical relationship commonly used in this type of application -- assuming a 5% savings for two plants[107].

$$P_2 = P_1(Q_2/Q_1)^x$$

where:

P_2 = price for Q_2 plants (or rating)

P_1 = price for Q_1 plants (or rating)

for:

$Q_2 = 2; \quad Q_1 = 1$

$P_2 = 2P_1 - 0.05(2P_1)$ (at 5% cost savings)

$P_2 = 1.9P_1$

therefore:

$1.9P_1 = P_1(2/1)^x$

$x = 0.93$

therefore:

$$P_2 = P_1(3/1)^{.93} \quad \text{for three units}$$

$$P_2 = 2.77\ P_1$$

Cost of three units:

$$P_2 = 2.77\ (\$724{,}834{,}000) = \$2{,}004{,}716{,}000$$

Capital cost per kw:

$$\text{Cap/kw} = \$2{,}004{,}716{,}000/4{,}500{,}000$$

$$= \$445/\text{kw}$$

Annual Interest

At 8% annually of capital debt

over project life (1974 dollars) = 0.08 x $2,004,716,000

= $160,377,280

Total interest during

operating life of project $= \dfrac{1.08^{30}-1}{.08(1.08)^{30}}\ (160{,}377{,}280)$

= $1,805,492,673

12. Fuel costs for a 1157 MWe HTGR (1973 dollars) are shown in Table 27[108].

Table 27

HTGR Fuel Costs

	First 6 years	Next 8 years
Uranium fabrication	\$ 7,200,000	\$ 6,500,000
Mixed oxide fabrication	7,200,000	9,414,000
Spent fuel service	4,600,000	6,000,000
Reflector blocks	300,000	600,000
Total (less U_3O_8)	\$19,300,000	\$22,514,000
Total (less U_3O_8) 1974 dollars	\$20,844,000	\$24,315,120
(Annual Interest at 8%)	(\$1,667,520)	(\$1,945,360)
Cost	\$20,844,000	\$72,945,360
Total cost 1974 dollars	\$93,789,360	

Interest: (at 8% over length of fuel cycle)

First 6 years $\$1,667,520 \left[\frac{(1.08)^6-1}{.08(1.08)^6}\right] = \$7,708,744$

Next 8 years $\$1,945,210 \left[\frac{(1.08)^8-1}{.08(1.08)^8}\right] = \$11,178,419$

Following 8 years $\$1,945,210 \left[\frac{(1.08)^8-1}{.08(1.08)^8}\right] = \$11,178,419$

Final 8 years = \$11,178,419

Present worth (1974) interest = \$41,244,000

Total with interest
(less U_3O_8) for 1157 MWe HTGR

Basic:	\$93,789,360
Interest:	41,244,000
	\$135,033,360

From "Nuclear Energy for Coal Gasification" by R. N. Quade and A. T. McMain[109], it is stated that U_3O_8 cost at \$7.5/lb represents 0.3% of the total fuel cost. Estimated costs at \$8.0/lb and \$10.0/lb are as shown in Table 28.

Table 28

Estimated U_3O_8 Costs

Price/lb	First 6 years	Next 24 (each 8)
\$ 7.5	.3/.7(19,300,000)	.3/.7(22,514,000)
	= \$8,271,429	= \$9,648,857
\$ 8.0	8/7.5(8,271,429)	8/7.5(9,648,857)
	= \$8,822,857	= \$10,292,114
\$10.0	10/7.5(8,271,429)	10/7.5(9,648,857)
	= \$11,028,571	= \$12,865,143

Estimated supply of Uranium at less than \$10/lb is anticipated for the next 35 years and will be used as the cost (1974 dollars) for uranium ore, U_3O_8[110]. Figures are shown in Table 29.

Table 29

Estimated Fuel Cost

Fueling Period	1973 Cost	1974 Cost	Annual Interest (at 8%)
First 6 years	\$11,128,571	\$11,910,857	\$ 952,869
Next 8 years	12,865,143	13,894,354	1,111,548
Following 8 years	12,864,143	13,894,354	1,111,548
Final 8 years	12,864,143	13,894,354	1,111,548
Totals	\$49,624,000	\$53,593,919	\$4,287,513

Interest on Fuel Financing at 8%

Fueling Period	Calculation	Amount
First 6 years	$(952,869)\left[\frac{(1.08)^6-1}{.08(1.08)^6}\right]$	\$ 4,404,999
Next 8 years	$(1,111,548)\left[\frac{(1.08)^8-1}{.08(1.08)^8}\right]$	6,387,665
Following 8 years	same	6,387,665
Final 8 years	same	6,387,665
Total; Interest:		\$23,567,994
Total; U_3O_8 plus interest:		\$77,161,913
Total; Less U_3O_8 plus intersts:		\$135,033,361
	Total	\$212,195,274

Assuming fuel costs are directly proportional to the quantity needed and that this amount is, in turn, directly proportional to the total power rating (4500 MWe):

$$\text{Total fuel costs (1974 present worth ore and fabrication)} = \frac{4500}{1157} \times \$212{,}195{,}274$$

$$= \$825{,}305{,}733$$

13. Operation and Maintenance, Administrative and General, and Insurance Costs:

The following estimates are based on WPSS #3 data from an October 1973 bond issue. Statements accompanying the following data indicate that it has been escalated to 1982 figures at 4%. De-escalation to a 1974 present worth value, and extrapolation throughout a 30 year project life are as shown in Table 30.

Table 30

Nuclear Power Plant Operation and Maintenance, Administrative and General and Insurance Costs

	1982(annual)	1974(annual)	x 30 years	Total
Operation and Maintenance	\$5,464,000	\$4,000,000	x 30	$\$120 \times 10^6$
Administrative and General	1,461,000	1,070,000	x 30	32.1×10^6
Insurance	2,000,000	1,462,000	x 30	43.9×10^6

Assuming operation, maintenance, administrative and general costs, and insurance costs conform to the following economies to scale[111]:

$$C = C_{ref}(MWe/MWe_{ref})^{0.7}$$

Operation and Maintenance = $120 \times 10^{6}(4500/1200)^{0.7}$

= \$302,693,527

Administrative and General = $32.1 \times 10^{6}(4500/1200)^{0.7}$

= \$80,970,518

Insurance = $43.9 \times 10^{6}(4500/1200)^{0.7}$

= \$110,735,382

14. Underground siting costs: Conflicting references to the cost of underground siting have been found in the literature[112]. The values used in this study are those taken seriously by the Boeing Company in their work costing various types of undergound installations, including nuclear power plants[113]. From the data of Fogarty et al it is estimated that the magnitude of the capital outlay required for a present day 1100 MWe PWR is approximately 50% of the capital cost of the PWR itself. General Atomic Company reveals that the containment volume for the HTGR is approximately 75% of that required for a PWR of the same rating[114]. This leads to a reduction in the costs for underground siting of an HTGR to approximately 37.5% of the capital cost of the plant above ground. Although General Atomic claims a significant cost reduction for HTGR's over PWR's, this reduction has not been assumed in this analysis due to the lack of specific economic data to support the claim. Therefore, the costs previously calculated for the HTGR can be used in place of PWR costs.

Obviously, a significant reduction in underground siting costs may be realized by siting three plants instead of one. In the absence of definitive data on the magnitude of economies to scale that might be realized the "Williams six tenths factor" will be used in the following relation:

$$C_3 = (3/1)^{0.6} C_1 = 1.932 C_1$$

$$C_3/C_1 \doteq 1.932$$

Calculations for three plants are found in previous sections. Therefore, based on a value of C_1 being 1/3 of this previously calculated cost:

$$C_3/3C_1 = 0.644$$

The overall fraction of the power plant capital cost is then:

$$C_{UG} = 0.644(37.5\%) = 24.2\% \text{ of } C_3\text{-HTGR-GT}$$

$$C_{UG} \approx 0.242 \times \$2{,}004{,}716{,}000$$

$$C_{UG} = \$484{,}435{,}122$$

Annual interest at 8%:

$$= \$38{,}754{,}810$$

Present growth of interest payments over 30 years:

$$PW_I = 38{,}754{,}810\left[\frac{(1.08)^{30}-1}{.08(1.08)^{30}}\right]$$

$$PW_I = \$436{,}293{,}255$$

Total present worth of capital and interest:

$$= \$920{,}728{,}377$$

APPENDIX J

Electrolysis Costs

The electrolysis costs estimates are based on information by Hallett[115] for a plant located in Los Angeles, California.

Escalation of 1967 Los Angeles costs to 1974 Seattle costs:

From the "Engineering New Record" (ENR) Construction Costs Index, Table 31 has been derived.

Table 31

	Los Angeles	Seattle
December 1967	100	100
March 1974	176	164

Capital Costs:

1974 Seattle = 1.64 x (1967 Los Angeles)

$= 1.64 \times \$31.35 \times 10^{6} \times (2000/250)^{.88}$ [116]

$= \$320.48 \times 10^{6}$

Operating Costs:

1974 Seattle = 1.64 x (1967 Los Angeles)

$= 1.64 \times (\$2.62 \times 10^{6} \times (2000/250)^{.73}$ [117]

$= \$19.61 \times 10^{6}$ per year

The factor $(2000/250)^{exp}$ is the estimate of increased plant costs for incrementally larger installations. In this case, eight 250 ton per day units are employed as determined in the size estimate of Appendix E.

Feed and Cooling Water

Costs are 1974 Seattle costs.

Annual requirement of feed and cooling water for electrolysis:[118]

$$= 20.5\#H_2O/\#GH_2 \times 1489.8T/D \times 365D/Y$$

$$= 11.15 \times 10^6 T/Y \ (0.93 \times 10^6 \ T/M)$$

Water costs on a monthly bases are determined and summed to provide an annual cost as shown in Table 32.

Table 32

Electrolysis Feed and Cooling Water Costs

Month	Load* Factor	Usage (T/M)	Usage (ft^3/M)	Cost
January	0.980	940,000	30.1×10^6	$30,100
February	0.876	840,000	27.0×10^6	27,000
March	0.988	947,000	30.4×10^6	30,400
April	0.988	947,000	30.4×10^6	30,400
May	1.084	1,038,000	33.3×10^6	33,300
June	1.116	1,068,000	34.3×10^6	34,300
July	1.028	985,000	31.6×10^6	31,600
August	1.028	985,000	31.6×10^6	31,600
September	0.964	924,000	29.6×10^6	29,600
October	1.012	970,000	31.1×10^6	31,100
November	0.968	924,000	29.6×10^6	29,600
December	0.980	940,000	30.3×10^6	30,300
1974 Seattle water cost total:				$379,300 per year

* See Appendix C for computation of load factor

(Cost based on \$.10/100 ft^3 for large quantities, City of Seattle, 1974.)

Cost Summary for Electrolysis:

Capital Costs	\$320,000,000
Interest	
(0.08)(320,480,000) = \$25,640,000/yr	
$\frac{25,640,000(1.08^{30}-1)}{(0.08)(1.08)^{30}}$ =	289,000,000
Operating Cost	
\$19,610,000 x 30 =	588,000,000
Feed and Cooling	
\$379,300 x 30 =	11,000,000
Total:	\$1,208,000,000

APPENDIX K

Liquifaction Costs:

The liquifaction costs estimates are based on information by Hallett[119] and locally obtained costs. Liquifaction design is based on Hallett[120] studies as applied to an electrolysis plant in Seattle (Appendix E).

Consumed Substances:

Methane: Cost estimate based on data supplied by Washington Natural Gas Company, Seattle, Washington[121].

Quantity/year (MCF)	Cost ($ per MCF)	Annual CH_4 Cost
261,400	1.36	$356,000

Nitrogen: Cost estimate based on doubling the cost of nitrogen since 1967 as listed in Hallett's study[122].

Quantity/year (MCF)	Cost ($/T)	Annual N_2 Cost
21.75×10^3	13.00	$283,000

Propane: Cost estimate based on doubling the cost of propane since 1967 as listed in Hallett's study[123].

Quantity/year (T/year)	Cost ($/T)	Annual C_3H_8 Cost
10,880	50.00	$544,000

Ethylene: Cost estimate based on doubling the cost of ethylene since 1967 as listed in Hallett's study[124].

Quantity/year (T/year)	Cost ($/T)	Annual C_2H_4 Cost
10,880	160.00	$1,741,000

Capital Investment:

From the "Engineering News Record" (ENR) Construction Cost Index:

	Los Angeles	Seattle
December 1967	100	100
March 1974	176	164

1974 Seattle = 1.64 x (1967 Los Angeles)

$= 1.64 \times \$34.7 \times 10^6 \times (2000/250)^{.8}$ [125]

$= \$300.4 \times 10^6$

Operating Costs:

1974 Seattle = 1.64 x (1967 Los Angeles)

$= 1.64 \times \$1.91 \times 10^6 \times (2000/250)^{.65}$ [126]

$= \$12.1 \times 10^6$

Present worth

over 30 years $= 30 \times \$12.1 \times 10^6$

$= 363.1 \times 10^6$

Cost Summary for Liquifaction:

Capital Cost			$\$300.4 \times 10^6$
Interest			
$(0.08)(300.4)10^6 = \$24.0 \times 10^6$			
$\dfrac{24.0 \times 10^6(1.08^{30}-1)}{(0.08)(1.08)^{30}}$		=	270.5×10^6
Operating Cost			363.1×10^6
Consumables			
CH_4	$30 \times 0.36 \times 10^6$	=	$\$10.8 \times 10^6$
N_2	$30 \times 0.28 \times 10^6$	=	8.4×10^6
C_3H_8	$30 \times 0.54 \times 10^6$	=	16.2×10^6
C_2H_4	$30 \times 1.74 \times 10^6$	=	52.2×10^6
Total (Present Worth)			$\$1022 \times 10^6$

APPENDIX L

Liquid Hydrogen Storage Costs:

From the estimates of Appendix E, four 4800 ton double wall, evacuated pearlite insulated tanks will be employed. (4800 tons = 96×10^5 lb) Using base cost data (C_b) for a tank of size S_b, the cost (C) for a tank of size S can be determined as follows:

$$C = C_b(S/S_b)^m$$

Determination of m:

$$m = \ln C/\ln[C_b(S/S_b)]$$ from manipulation of the above relation

From tank cost data by Hallett (1967)[127]:

for $S = 72 \times 10^5$ lb; $C = \$72 \times 10^5$ (values identical by coincidence)

for $S_b = 6 \times 10^5$ lb; $C_b = \$7.4 \times 10^5$

$$m = \frac{\ln (72 \times 10^5)}{\ln[(7.4 \times 10^5)(72 \times 10^5/6 \times 10^5)]}$$

$$= 0.99$$

Cost of a single 96 lb storage tank then is :

$$C = 72 \times 10^5(96 \times 10^5/72 \times 10^5)^{.99} = \$95.6 \times 10^5$$

Cost for four tanks:

$$= \$382 \times 10^5 \quad (1967)$$

Cost - 1974 Seattle:

$$= 1.64\ (382 \times 10^5)$$

$$= \$62.6 \times 10^6$$

Interest per year at 8%:

$$= \$5.01 \times 10^6$$

Present Worth of Annual Interest Payments over 30 Years:

$$PW = I\ \left[\frac{(1 + \phi)^n - 1}{(1 + \phi)^n}\right] = \frac{5.01 \times 10^6\ [(1.08)^{30} - 1]}{.08(1.08)^{30}}$$

$$= \$56.6 \times 10^6$$

Maintenance:

Maintenance and operation costs are assumed small relative to, and included in, the liquifaction plant maintenance costs.

Cost Summary for Storage:

Capital:	$\$62.6 \times 10^6$
Interest:	56.6×10^6
Total:	$\$119.2 \times 10^6$

APPENDIX M

Space and Process Heat Distribution Costs

Heat Distribution:

Tapiola Garden City, Finland is a planned community incorporating a district heating and electrical system. Costs are scaled from this facility. Specifications are[128]:

Capacity of distribution system	77.5 MMBTU/hr
Capital cost (1970)	\$2,843,750
Total length of system	13.7 miles
Overall thermal efficiency	80.8%
(power plant efficiency is about 25%)	

Although it is not likely that all exhausted heat could be used in a heating-absorption air conditioning network, by including the transmission of process heat at elevated exhaust temperatures, such as available, using the HTGR-GT cycle, utilization of 70% of the rejected heat is assumed.

Heat rejected by 4500 MWe HTGR-GT plants operating at a load factor of 85%:

$$= 3.414 \times 10^6 \text{ BTU/MW}(4500/0.37 - 4500)(0.85)$$

$$= 22.23 \times 10^9 \text{ BTU/hr}$$

Heat utilized at 0.7 recovery factor:

$$= 1.556 \times 10^{10} \text{ BTU/hr}$$

1974 capital cost for the 77.5 MMBTU/hr facility:

ENR construction cost index - 1970 = 1386[129]

ENR construction cost index - 1974 = 2083

$$\text{Capital Cost (1974)} = \text{Capital Cost 1970} \left(\frac{\text{ENR 1974}}{\text{ENR 1970}}\right)$$

$$= 2.844 \times 10^6 (2083/1386)$$

$$= \$4.27 \times 10^6$$

Scaling up distribution system capital costs to 1.556×10^{10} BTU/hr:

$$C = C_b (S/S_b)^m$$

Where m = an exponential scale up factor, conservatively selected as 0.8.

$$C = 4.274 \times 10^6 (1.556 \times 10^{10})/7.75 \times 10^7)^{0.8}$$

$$C = \$297.2 \times 10^6$$

PW of interest over 30 years at 8%:

Annual $= 0.08(297.2 \times 10^6) = \$23.77 \times 10^6$

Present worth over 30 years of payment:

$$PW = 23.77 \times 10^6 \frac{[(1.08)^{30} - 1]}{.08(1.08)^{30}}$$

PW Interest = $\$267.6 \times 10^6$

Estimate of operating costs:

No specific value is provided in the literature. Therefore, a conservative estimate is made based on the present worth of operating costs

system are presumed to be no more costly than this since it is a relatively simple system:

$$\frac{\text{Op. Cost Liq.}}{\text{Cap. Cost Liq.}} = \frac{383.1 \times 10^6}{300.4 \times 10^6} = 1.28 = \frac{\text{Op. Ht. Distr.}}{\text{Cap. Ht. Distr.}}$$

$$\text{Op. Cost Ht. Distr.} = 1.28\ (297.2 \times 10^6)$$

$$= \$380.4 \times 10^6$$

Present Worth Cost Summary for Heat Distribution:

Capital Cost	$\$297.2 \times 10^6$
Interest (present worth)	267.6×10^6
Operating Cost	380.4×10^6
Total	$\$945.2 \times 10^6$

APPENDIX N

Defogging System Costs

Defogging appears feasible and warranted for the Seattle-Tacoma Airport as shown in the estimates and feasibility studies of Appendix H.

It is assumed, conservatively, that defogging apparatus such as that envisioned for the Seattle-Tacoma Airport would cost approximately three times the cost of a single cooling tower of identical capacity. Although sketchy cost estimates for structures housing fossil fueled defogging heat generators have been found in the literature, no in-depth study of dry, hot air driven units were located[130].

Cost of dry cooling towers: $9/installed KWe (1972)[131]

$$1974\ \text{Cost: } 3 \times \left[\frac{\text{ENR CCI (1974)}}{\text{ENR CCI (1972)}}\right] \times 9 = \$9.9/\text{installed KWe} \times 3$$

$$= \$29.7/\text{installed KWe}$$

Heat (BTU) capacity per installed KWe:

Efficiency assumed to be 30% per source estimate[132]

Heat (KW) capacity:

$$\frac{1\text{KWe}}{.30} - 1\ \text{KWe} = \frac{0.7}{0.3} = 2.3\ \text{KW (heat)}$$

Heat (BTU) capacity:

$$2.3\ \text{KW} \times 3413\ \text{BTU/KW} = 7850\ \text{BTU/hr}$$

Capital Cost:

$$= \frac{29.7 \times 1.59 \times 10^9}{7.85 \times 10^3} = \$6.02 \times 10^6$$

Annual Interest due at 8%:

$$= 0.08(6.02) \times 10^6 = \$0.48 \times 10^6/\text{yr}$$

Present worth of annual interest payments over 30 years:

$$= \frac{0.48 \times 10^6[(1.08)^{30}-1]}{0.08(1.08)^{30}}$$

$$= \$5.42 \times 10^6$$

Maintenance is assumed small and included in power plant costs.

Defogging Cost Summary:

Capital cost	$\$6.02 \times 10^6$
Present worth interest	5.42×10^6
Total	$\$11.44 \times 10^6$

APPENDIX O

Fuel Benefit

The price paid by the major air carriers for commercial aircraft fuel is closely guarded, proprietary information. Direct contact with various suppliers resulted in no data whatsoever. Unofficial, but reliable, information was obtained, however, as follows:

1. Commercial contracts run about \$.28 to \$.29/gal for the major carriers.
2. Retail costs through airports for other carriers runs from \$.41 to \$.43/gal.
3. Aviation gas to private consumers is \$.70 to \$.75/gal.
4. Bonded foreign fuel for overseas flights costs the commercial carriers about \$.60/gal. Bonded fuel must be used by the air carriers for flights terminating in foreign countries.
5. The 1973 cost of commercially contracted fuel was \$.14 to \$.15/gal.
6. The 1974 price appears to be stable, with no decrease in price likely in the near future, and no drastic escalation like that seen in the 1973-1974 year likely either.

<u>Estimated annual fuel consumption by wide body aircraft at Seattle-Tacoma Airport in 1990</u>

$$\text{Consumption (T/yr)} = Jg_{wb}f_{1990}(\text{bbl/d})(.1367\text{T/bbl})(365/\text{y})$$

$$= (15246)(10.21)(.1823)(.1367)(365)$$

$$= 1.416 \times 10^6 \text{ T/yr}$$

$$(\text{gal/yr}) = \frac{1.416 \times 10^6 \text{ T/yr} \times 2000 \text{ lbT} \times 7.48 \text{ g/ft}^3}{48.7 \text{ lb/ft}^3}$$

$$= 4.35 \times 10^8 \text{ gal/yr}$$

Annual Revenue at $.29/gal:

$$= 0.29 \times 4.35 \times 10^8$$

$$= 1.26 \times 10^8$$

Present worth of annual revenue income over 30 years:

$$= 30 \times 1.26 \times 10^8$$

PW Fuel Benefit: $= \underline{\$3.78 \times 10^9}$

<u>Bonded fuel data on the present worth of the fuel benefit:</u>

Let g_b = The fraction of wide body jet fuel required to be bonded fuel.

B_{fb} = The annual benefit derived from the displacement of bonded fossil jet fuel

B_{fd} = The annual benefit derived from the displacement of domestic fossil jet fuel.

p_b = Present price of bonded fossil jet fuel.

p_d = Present price of domestic fossil jet fuel.

Then:

$$B_{fb} = g_b \times p_b (4.35 \times 10^8 \text{ gal/yr})$$

And:

$$B_{fd} = (1-g_b)(4.35 \times 10^8 \text{ gal/yr}) p_d$$

The foregoing relations lead to the data shown in Table 33.

Table 33

Fuel Benefit as a Function of Bonded Fuel Displaced by Hydrogen

g_b	B_{fb}	B_{fd}	B_f	$PW_f (=B_f x30)$	Increase
0.0	0.0	1.26×10^8	1.26×10^8	3.78×10^9	
0.05	0.13×10^8	1.20×10^8	1.33×10^8	3.99×10^9	0.21×10^9
0.10	0.27×10^8	1.14×10^8	1.41×10^8	4.23×10^9	0.45×10^9
0.15	0.39×10^8	1.07×10^8	1.46×10^8	4.38×10^9	0.60×10^9
0.20	0.52×10^8	1.01×10^8	1.53×10^8	4.59×10^9	0.81×10^9
0.25	0.65×10^8	0.95×10^8	1.60×10^8	4.80×10^9	1.02×10^9
0.30	0.78×10^8	0.88×10^8	1.66×10^8	4.98×10^9	1.20×10^9
0.50	1.31×10^8	0.63×10^8	1.94×10^8	5.82×10^9	2.04×10^9

APPENDIX P

Electricity Benefit

The data in Table 34 that follows has been developed by Seattle City Light and is continually updated for use in their long-term nuclear policies. From the set of data shown here, (effective in March 1974), it is seen that the cost of electricity for a nuclear plant in 1990, going on the line in 1990, is 16.13 mills/kw-hr.

Present worth of 16.13 mills/kw-hr in 1990:

$$PW\ 1974 = 16.13/(1.08)^{16} = 4.71 \text{ mills/kw-hr}$$

From calculations of Appendix D the monthly average capacity of electricity available for commercial sale has been determined. This data is used in Table 34.

Present worth of revenue from the sale of electricity over 30 years:

$$PW_{1974} = (30)(41.63) \times 10^6 = \$1.25 \times 10^9$$

Table 34

Monthly Average Revenue from the Commercial Sale of Electricity

Month	Capacity	Energy Cost (mills/kw-hr)	#Hrs/Mo.	Revenue ($\$10^6$)
January	1071.0	4.71	744	3.76
February	1362.7	4.71	672	4.31
March	1048.6	4.71	744	3.67
April	1048.6	4.71	720	3.55
May	779.3	4.71	744	2.72
June	689.6	4.71	720	2.34
July	936.4	4.71	744	3.28
August	936.4	4.71	744	3.28
September	1115.9	4.71	720	3.78
October	981.3	4.71	744	3.44
November	1106.7	4.71	720	3.74
December	1071.0	4.71	744	3.76
			Annual Total	41.63

Table 35

Nuclear Energy Costs

Design Calculations
City of Seattle - Department of Lighting
(Inflationary Forecast @ 80% Plant Factor)

			1973	1975	1980	1985	1990	1995	2000
CAPITAL COST $/KW			300	360	530	650	860	1030	1200
FIXED CHARGES @ 9.86% and 80% PF	MILLS/KWH FOR START-UP DATE OF	1973	4.22						
		1975		5.6					
		1980			7.5				
		1985				9.14			
		1990					12.10		
		1995						14.5	
		2000							16.88
O & M (@ 6%) MILLS/KWH(esc./yr)			.47	.63	.84	1.13	1.5	2.0	2.7
MILLS/KWH	MILLS/KWH FOR START-UP DATE OF	Heat Rate	10,300	10,300	10,000	9,500	9,250	9,000	8,500
		¢/MBTU	16.7	17.7	20.5	23.7	27.5	31.9	37.0
		1973	1.72	1.82	2.11	2.44	2.83	3.28	3.81
		1975		1.82	2.11	2.44	2.83	3.28	3.81
		1980			2.05	2.37	2.75	3.19	3.7
		1985				2.25	2.61	3.03	3.51
		1990					2.53	2.95	3.42
		1995						2.87	3.33
		2000							3.14
MILLS PER KWH	TOTAL @ START-UP		6.41	7.51	10.34	12.52	16.13	19.37	22.72
TOTAL AFTER START UP MILLS/KWH	MILLS/KWH FOR START-UP DATE OF	1973	6.41	6.67	7.17	7.79	8.55	9.50	10.73
		1975		7.51	8.01	8.63	9.39	10.34	11.57
		1980			10.34	10.95	11.70	12.64	13.85
		1985				12.52	13.25	14.17	15.35
		1990					16.13	17.05	18.22
		1995						19.37	20.53
		2000							22.72

APPENDIX Q

Space and Process Heating Benefits

As pointed out in the technical feasibility study, a considerable amount of rejected heat is available at high temperatures. Although the difficulty of utilizing all of this heat is recognized, approximately 70% utilization is assumed. Because of the high temperatures involved, chemical and other process heat utilizing industries are expected to locate in the vicinity of the power plant in order to utilize this energy. Housing, hotels, apartments, and industrial space heating requirements are expected to be met within, conservatively, a six mile radius[133].

Assuming that the least expensive fossil fuel available to industries in 1990 will be coal from the nearby Montana or Wyoming mines, the following heat benefit will be realized:

Cost of coal:

Information on file with the Environmental Protection Agency, Seattle, pertaining to the benefit-cost analysis of the Trojan Nuclear Plant indicates a cost (1973) at the site for coal is $8.00 per ton. This figure represents a cost of $.11/MMBTU at the mine and transportation cost of $6.16/ton[134].

Coal from Montana and Wyoming is predominantly sub-bituminous, rated slightly below 10,000 BTU/lb.

$$\text{Heating rating} = 2000 \text{ lb/T} \times 10{,}000 \text{ BTU/lb}$$

$$= 20.0 \times 10^{6} \text{ BTU/T}$$

Heat rejected from a power plant complex: (0.85 pwr fac.)

$$= (3.414 \times 10^6 \text{ BTU/MW})(4500 \text{ MWe}/0.37 \text{ MWe/MW} - 4500 \text{ MW})(.85)$$

$$= 22.2 \times 10^9 \text{ BTU/hr}$$

Assuming 70% utilization for space heating and process heating applications:

$$= 22.2 \times 10^9 \times 0.70 = 15.56 \times 10^9 \text{ BTU/hr}$$

Quantity of coal required to produce the above amount of heat:

$$= (15.56/20.00) \times 10^3 \text{ T/hr}$$

$$= 778.2 \text{ T/hr}$$

Annual revenue from the sale of heat at a price equivalent to $8.00/T coal:

$$= \$8.00/\text{T } (778.2 \text{ T/hr})(8760 \text{ h/yr})$$

$$= \$54{,}700{,}000$$

Present worth of annual revenue from the sale of heat over 30 years:

$$= 30 \times \$54{,}700{,}000$$

$$= \$1.64 \times 10^9$$

An alternative estimate for the benefit from the sale of process and space heat

The University of Washington has converted its heating plant to coal for slightly less than one third of its heat demand, or approximately 13,000 tons/year. 1974 coal costs were only $10.00/ton. The 1975 costs, however,

will be \$18.50 due to escalating energy costs in general, and, in particular, to the increased wages to miners as a result of the recent settlement of the coal miners strike.

Placing the 1975 cost of coal in 1974 dollars at 8%

$$\begin{aligned} \text{Coal cost (1974)} &= \text{Cost 1975}/1.08 \\ &= \$18.50/1.08 \\ &= \$17.13/\text{ton} \end{aligned}$$

Coal is burned at 83% efficiency in the University of Washington power plant facilities, and the coal has a heat rating of 12,500 BTU/lb (Utah bituminous).

Effective heat utilization per ton:

$$= 12{,}500 \text{ BTU/lb} \times 2000 \text{ lb/ton} \times 0.83 \text{ BTU used/BTU rated}$$

$$= 20.8 \times 10^{6} \text{ BTU/ton}$$

Quantity of Coal required to produce 15.56×10^{9} BTU/hr, the expected useful rejected heat from the nuclear plant as shown on the previous page:

$$= (15.56/20.8) \times 10^{3} = 748 \text{ tons/hr}$$

Annual revenue from the sale of heat at a price equivalent to \$17.13/ton coal:

$$= \$17.13/\text{ton } (748 \text{ tons/hr})(8760 \text{ hr/yr})$$

$$= \$112{,}200{,}000$$

Present worth of annual revenue from the sale of heat over 30 years:

$$= 30 \times \$112{,}200{,}000$$

$$= 3.36 \times 10^{9}$$

APPENDIX R

Fog Dispersal Benefit

Appendix H demonstrated the technical feasibility of utilizing rejected heat from the HTGR-GT for fog dispersal. The data of Table 36 produced by the Federal Aviation Administration, Department of Transportation, provide estimated benefits from the dispersal of fog in the terminal area[135]. The data is presented in two columns: one including benefits from the reduction in passenger delays and the other without incorporating this benefit. Other benefits included are the average costs of such weather associated flight disruptions as delays, diversions, and cancellations of scheduled landings. Since the specific category of passenger delay is large relative to the other costs, and in view of the wide range of values yielded by the different approaches proposed to the FAA for the referenced study, the two estimates are provided.

It is apparent from the data of Table 36 that significant savings are possible for the Seattle-Tacoma Airport, ranking fifth highest among the 39 airports included in the study.

Estimated 1974 annual fog dispersal benefit:

$$B_{fog} = (1 + j)^3 B_{fog\ 1971} = (1.08)^3 (2.48 \times 10^6)$$

$$= \$3.135 \times 10^6$$

Present worth of above benefit over 30 years:

$$PW_{fog} = 30 \times 3.135 \times 10^6 = \$94.0 \times 10^6$$

Table 36

Potential Economic Benefits of Fog Dispersal in the Terminal Area, Federal Aviation Administration, Department of Transportation, Part III Washington, D.C. 1971

Airport	1971 Without Passenger Delay Incorporated ($1000)	Benefits With Passenger Delay Incorporated ($1000)
Anchorage, Airport, Anchorage, AK	107	257
Atlanta Airport, Atlanta, GA	1302	3840
Friendship International, Baltimore, MD	443	1325
Birmingham International, Birmingham, AL	----	68
Buffalo International, Buffalo, NY	215	579
O'Hare International, Chicago, IL	1130	3463
Cincinnati Airport, Covington, KY	218	615
Cleveland-Hopkins International, Cleveland, OH	227	582
Port Columbus, Columbus, OH	96	281
Lowe Field, Dallas, TX	139	410
James M. Cox, Mun., Dayton, OH	137	397
Stapleton International, Denver, CO	96	254
Metropolitan Wayne Co., Detroit, MI	546	1663
Bradley International, Windsor Locks, CT	157	480
Houston Intercontinental, Houston, TX	449	1327
Indianapolis Mun., Indianapolis, MN	149	416
Kansas City Mun., Kansas City, MO	329	1169
Los Angeles International, Los Angeles, CA	1295	4183
Standiford Field, Louisville, KY	55	156
Miami International, Miami, FL	114	311
Gen. Mitchell Fd., Milwaukee, WI	253	748
Minnesota-St. Paul International, MN	117	319
Metropolitan, Nashville, TN	62	169
Newark Airport, Newark, NJ	396	1132
New Orleans International, New Orleans, LA	302	789
JFK International, New York, NY	1580	4861
LaGuardia, New York, NY	390	1110
Met. Oakland A/P, Oakland, CA	34	100
Philadelphia International A/P, Philadelphia, PA	512	1466
Greater Pittsburg International, Pittsburgh, PA	394	927
Portland International A/P, Portland, OR	427	1272
Rochester-Monroe County, Rochester, NY	69	185
Lambert-St. Louis Mun., St. Louis, MO	218	588
Salt Lake City Mun., Salt Lake City, UT	182	467
San Francisco A/P, San Francisco, CA	436	1234
Seattle-Tacoma A/P, Seattle, WA	832	2485
Clarence E. Hancock A/P, Syra, NY	49	126
Dulles International, Washington, DC	366	1102
Washington National, Washington, DC	274	802
39 Airports	14791	43353

APPENDIX S

Oxygen Benefit

The utilization of high purity oxygen, produced as a by-product, is anticipated; though such large quantities are produced that the demand market will be affected and the price, therefore, speculative. A rough estimate is hereby provided, by using the cost of producing oxygen by present day air liquifaction technology[136]. The oxygen availability would probably draw industries to the vicinity of the electrolysis plant, and, though in a sense seemingly unwise because of such high purity, it could easily be used in urban waste treatment facilities.

Quantity of oxygen produced:

$$O_2\ (T/yr) = 7.92\ T\ O_2/T\ H_2 \times (T\ H_2\ \text{produced})$$

$$H_2 = LH_{2F}/0.882 + 2.85\ T/D$$

$$= 1487 + 2.85 = 1490\ T/D$$

$$O_2\ (T/yr) = 1490\ T/D\ (7.92\ T\ O_2/T\ H_2)(365\ D/yr)$$

$$= 4.31 \times 10^6\ T/yr$$

Annual revenue at \$6.00/ton:

$$= \$6.00/T(4.31 \times 10^6\ T/yr)$$

$$= \$25.8 \times 10^6$$

Present worth of annual oxygen revenues over 30 years:

$$= 30 \times \$25.8 \times 10^6$$

$$= \$775.0 \times 10^6$$

APPENDIX T

Cost of Liquid Hydrogen

Cost of Electrolysis Power:

Average capacity dedicated to LH_2 production:

2810 MWe (see Appendix D)

Cost = 2810/4500 x 6.05 x 10^9 = \$3.78 x 10^9

Cost of Electrolysis: \$1.23 x 10^9

Cost of Liquifaction: \$1.02 x 10^9

Cost of LH_2 Storage: \$0.12 x 10^9

Cost of Heat Distribution prorated to the fraction of total power plant capacity dedicated to the production of liquid hydrogen:

2810/4500 x 0.95 x 10^9 = \$0.59 x 10^9

Cost of Defogging prorated to the fraction of total power plant capacity dedicated to the production of liquid hydrogen:

2810/4500 x 0.01 x 10^9 = \$0.01 x 10^9

Total Cost: \$6.75 x 10^9

Benefits gained in excess of those direct benefits associated with the sale of LH_2:

Defogging: \$0.09 x 10^9

Heat prorated to the fraction of total power plant capacity dedicated to the production of LH_2:

$$2810/4500 \times 1.64 \times 10^9 = \$1.02 \times 10^9$$

Oxygen: $\$0.78 \times 10^9$

Total: $\$1.89 \times 10^9$

Net Cost: (Total Cost - Total Benefits above)

$$= (6.75 - 1.89) \times 10^9 \quad = \$4.86 \times 10^9$$

Annual Cost:

$$4.86 \times 10^9/30 \quad = \quad \$0.16 \times 10^9$$

Quantity of LH_2 (lbs) produced per year:

$$1309.x\ T/D \times 365\ D/Y \times 2000\ T/lb = \underline{955 \times 10^6\ lb/yr}$$

Cost per pound:

$$\$0.16 \times 10^9/955 \times 10^6 = \underline{\$0.168}$$

Cost per 10^6 BTU:

$$\$0.168 \text{ per lb}/0.0515\ 10^6 \text{ BTU per lb} =$$

$$\$3.26 \text{ per } 10^6 \text{ BTU}$$

APPENDIX U

Fossil Jet Fuel Escalation Rate Analysis

Monetary benefit from fuel required to achieve a BCR = 1:

Net Deficit (from Costs and Benefits Summary)

= \$1,840,000,000

Fuel Benefit (calculated at 8% escalation rate)

= \$3,780,000,000

Total Required

Benefit, PW = \$5,620,000,000 (PW 1974)

Annual Benefit

Estimate = $\$3.78 \times 10^9/30$

$F = \$0.126 \times 10^9$

Present worth as a function of the escalation rate (j), social rate of discount (ϕ), and annual benefit required (F) at social rate of discount (ϕ) can be expressed as:

$$PW = \left(\frac{1+j}{1+\phi}\right)^a \left(\frac{1+j}{j-\phi}\right) \left[\left(\frac{1+j}{1+\phi}\right)^b - 1\right] F$$

rearranging:

$$\left(\frac{1+j}{1+\phi}\right)^a \left(\frac{1+j}{1-\phi}\right) \left[\left(\frac{1+j}{1+\phi}\right)^b - 1\right] - \frac{PW}{F} = 0$$

where:

$\phi = 0.08$

j = to be determined

$a = 1990 - 1974 = 16$

$b = 2020 - 1990 = 30$

$$\left(\frac{1+j}{1.08}\right)^{16}\left(\frac{1+j}{j-0.08}\right)\left[\left(\frac{1+j}{1.08}\right)^{30} - 1\right] - \left(\frac{3.78}{0.126}\right) = 0$$

$j = 9.4\%$

Bonded fuel is more expensive than domestically obtained fuel. Calculations for the present worth of the fuel benefit were presented in Appendix O. The data shown in Table 37 utilizes these calculations to determine the required rate of escalation in fuel costs in future years to achieve a benefit-cost ratio of one within the assumptions of this evaluation.

Table 37

Escalation Rate of Fuel Costs Required to Achieve a BCR of 1

g_b	PW (10^9\$)	F (10^9\$)	j (%)
0	3.78	0.126	9.4
0.05	3.99	0.133	9.2
0.10	4.23	0.141	9.0
0.15	4.38	0.146	8.8
0.20	4.59	0.153	8.7
0.25	4.80	0.160	8.5
0.30	4.98	0.166	8.4
0.50	5.82	0.194	7.9

Where the fraction of fuel obtained at bonded prices, g_b, is $.60/gal in 1974.

APPENDIX V

Recommendations for Future Evaluations

This preliminary evaluation employs many approximations and assumptions in the proposed design and economic evaluation that could provide researchers many hours of more detailed design and economic calculations leading to a more complete study and to alternative possibilities for the production of liquid hydrogen fuel for aircraft. The synergistic applications evaluated may be varied and expanded with a more extensive search of the literature. Other disciplines available at the University of Washington can be employed to evaluate in greater detail technologies capable of utilixing the forms of energy available from the proposed preliminary designs.

Table 38 provides one possible approach for future research into the concept studied in this report. The relations developed throughout this report are designed to provide a rapid means for determining the overall effect of the various parameters that go into determining the system power requirements and the economic impacts. For instance, variations in electrolysis efficiency, energy for liquifaction, storage losses etc., may be quickly inserted into the relation for total electrical power requirements (MW_{LH_2}) to find the subsequent impact on the size and number of nuclear, electrolysis, and liquifaction plants that will be required under the new conditions.

Table 38

RECOMMENDED VARIATIONS FOR FUTURE STUDY

PARAMETER	REFERENCE EVALUATION	HIGH (H) PRIORITY VARIATIONS	OTHER HIGH (H) AND LOW (L) PRIORITY VARIATIONS
I Plant Design			
a) Nuclear source	HTGR-GT	GC/LMFBR (H)	Chemo-nuclear source (H)
b) Conversion to thermal	gas-turbine (HTGR-GT)		
c) Converstion to electrical	gas-turbine electrical generator		
d) Conversion to chemical (H_2)	electrolysis		Chemo-nuclear (H), Direct thermal (L)
e) Thermal heat sink	dry cooling (located of defogging and space/process heat use)	Wet cooling (H)	
f) By-product heat use	defogging, space/process heat applications		
g) By-product electrical use	transmitted to local grid		
h) LH_2 transport	transmitted to local storage		
i) LH_2 storage	above ground local storage		
j) By-product O_2	to atmosphere or user facilities	Specified local industry (H)	
II Plant Construction			
a) Reactor	underground	above ground (H)	
b) Thermal plant	above ground		
c) Electrical plant	above ground		
d) Hydrogen/O_2 plant	above ground		
III Plant Location			
a) Reactor	airport property	Near large water source (H)	On water, floating (H)
b) Thermal	airport property		
c) Electrical	airport property		
d) Hydrogen/Oxygen	airport property		
e) Liquifaction	airport property		

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Thesis
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A technical and economic evaluation of using a nuclear energy source to produce liquid hydrogen for use as an aircraft fuel.